ALASKA LNG

DOCKET NO. CP17-___-000

RESOURCE REPORT NO. 10

ALTERNATIVES

PUBLIC

DOCUMENT NUMBER: USAI-PE-SRREG-00-000010-000

RESOURCE REPORT NO. 10 SUMMARY OF FILING INFORMATION [1]	
Filing Requirement	**Found in Section**
Address the "no action" alternative. (§ 380.12(l) (1)). • Discuss the costs and benefits associated with the alternative.	10.2
For large projects, address the effect of energy conservation or energy alternatives to the Project. (§ 380.12(l) (1)).	10.2.1
Identify system alternatives considered during the identification of the Project and provide the rationale for rejecting each alternative. (§ 380.12(l) (1)). • Discuss the costs and benefits associated with each alternative.	10.3.1, 10.4.1
Identify major and minor route alternatives considered to avoid impact on sensitive environmental areas (i.e., wetlands, parks, or residences) and provide sufficient comparative data to justify the selection of the proposed route. (§ 380.12(l) (2) (ii)). • For onshore projects near to offshore areas, be sure to address alternatives using offshore routings.	10.4.2
Identify alternative sites considered for the location of major new aboveground facilities and provide sufficient comparative data to justify the selection of the proposed site. (§ 380.12(l) (2) (ii)).	10.3.2, 10.5.2

[1] Guidance Manual for Environmental Report Preparation, Volume I (FERC, 2017). Available online at: https://www.ferc.gov/industries/gas/enviro/guidelines/guidance-manual-volume-1.pdf.

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BLM	9/26/2016	When the requirement for ultra-low sulfur diesel came into effect there was a decision made not to put a desulfuring plant on the north slope. As a result, truck traffic hauling diesel up the Dalton Highway increased considerably, and truck rollovers with fuel spills went from one every couple of years to 7 or 8 in one year. Given the amount of diesel required for this project, the applicant may want to consider including a desulfuring plant on the north slope. If not, then the EIS needs to include a thorough analysis of the risks of fuel spills, associated costs, and potential mitigations associated with the expected increase in trucking of fuel on the Parks and Dalton Highways.	Comment acknowledged.
BLM	9/26/2016	Relocating this proposed compressor station to an area using natural topographic land breaks between the compressor station and Galbraith Lake could reduce or alleviate these impacts.	Compressor stations are located based on pipeline hydraulics and geotechnical investigations, and have been sited accordingly.
EPA	9/30/2016	We recommend continued evaluation of the mainline pipeline route to avoid the Minto Flats wetland area. There are known cultural, archaeological and historic resources that should be avoided, as well as important aquatic resources of the Minto Flats State Game Refuge.	See Section 10.4.4.3 for Route Revisions of the Proposed Alternative.
EPA	9/30/2016	The AK LNG Project mainline pipeline route proposes to maintain at least five gas interconnection points to allow for future in-state deliveries of natural gas. We recommend that alternatives for the location of gas interconnection points include one that can be located for future use of natural gas in and/or near the Park. Natural gas would support existing public and private businesses and facilities, and future development near the Park entrance and visitors center, and within the Park boundaries while preserving existing air quality Class I resources.	The Applicant will address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	The Denali National Park Improvement Act (2013) authorizes the Secretary of the Interior to issue right of-way permits for a natural gas transmission pipeline in the Park in non-wilderness areas and with, along, or near the approximately seven-mile segment of the George Parks Highway. In addition, the right-of-way permit may only be issued where the NEPA analysis demonstrates that the route through the Park has the least adverse environmental effects. We recommend that the relevant Reports disclose and discuss how the DNPP minor route variation would meet the requirements of the Act. The DNPP route variation is a reasonable alternative under NEPA, and because of the potential to locate the pipeline within existing infrastructure rights-of-way, may represent the least environmentally damaging practicable alternative pursuant to the Clean Water Act (CWA) Section 404(b)(1) Guidelines.	See Applicant's response to scoping comments regarding the Denali National Park and Preserve Alternative posted to the FERC Docket on 11/15/2016 (Accession No. 20161115-5014).
EPA	9/30/2016	On the east side of Cook Inlet on the Kenai Peninsula, Nikiski was identified as the preferred site for the LNG Plant and marine terminal. Directly north of the preferred site is the Agrium Facility and the Kenai LNG Plant. Both facilities support an existing marine terminal. The Reports should evaluate the redevelopment and expansion alternatives for the Agrium Fertilizer Facility and the Kenai LNG Plant to support the proposed LNG Plant and Marine Terminal. The Agrium Facility is currently out of service and has not been operational since 2007. The Reports should evaluate the Agrium Facility site as a reasonable alternative for the AK LNG Plant. The redevelopment of the Agrium Facility would avoid	See Section 10.3.2.5. The Applicant will address this comment prior to the issuance of the DEIS.

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		disturbing and impacting new areas around Nikiski. The existing Kenai LNG Plant, north of the Agrium Facility, maintains an active marine terminal sized for smaller volume LNG carriers (87,500 cubic meters to 138,000 cubic meters). We recommend that the Reports discuss the expansion of the Kenai LNG Plant to support the AK LNG Plant as a reasonable alternative.	
EPA	9/30/2016	We recommend that the relevant Reports include the evaluation of an offshore open water disposal site alternative. Alternatives should also include evaluation of beneficial uses of dredged material, including beach nourishment, shoreline stabilization, and erosion protection, fill for project development, and upland disposal. We recommend that the sampling and analysis plan, and the marine dredging and disposal plan be included as an appendix to the Reports. We also recommend that the Reports include the characterization of the marine benthic environment and mapping of the seafloor geomorphology in Cook Inlet and Prudhoe Bay, including the distribution of submerged aquatic vegetation, such as eelgrass. Turbidity plume and water column testing/modelling should be conducted to evaluate the magnitude and distribution of sediment plumes associated with dredging, and different dredging and disposal methods. Turbidity testing/modelling should also be conducted for the placement of the subsea mainline pipeline across Cook Inlet.	No longer applicable. There is no dredging proposed in Prudhoe Bay.
EPA	9/30/2016	The Reports indicate that along the mainline pipeline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. Three approximate locations of the gas interconnection points have been tentatively identified to serve the Fairbanks area, the Matanuska-Susitna Valley and Anchorage, and the Kenai Peninsula. We recommend that a fourth gas interconnection point be located along the mainline pipeline to allow for future use of natural gas in and/or near the Denali National Park and Preserve (Park) boundaries. Natural gas would support existing public and private businesses and facilities, and future development near the Park entrance and visitors center, and within the Park boundaries.	The Applicant will address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	Liquefaction Facility Siting Conclusions - The Nikiski site was chosen as the Applicant's proposed alternative site. North of the proposed AK LNG Plant site is the Agrium Facility and the Kenai LNG Plant. Both facilities are equipped with a marine terminal. The Reports should evaluate the use of the Agrium Facility and the Kenai LNG Plant to support the AK LNG Plant and Marine Terminal. The Agrium Facility is currently out of service and has not been operational since 2007. The Reports should evaluate the Agrium Facility site as a reasonable alternative for the AK LNG Plant site. We recommend evaluation of redeveloping the Agrium Facility for the AK LNG Plant in the Reports. This would avoid disturbing and impacting new areas in near Nikiski. The existing Kenai LNG Plant is north of the Agrium Facility in Nikiski along Cook Inlet. The existing marine terminal is sized for smaller volume LNG carriers (87,500 cubic meters to 138,000 cubic meters). We recommend that the Reports discuss the expansion of the Kenai LNG Plant, as a reasonable alternative.	See Section 10.3.2.5. The Applicant will further address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	MOF near Beluga – The Reports should include an evaluation of the proposed MOF on the west side of Cook Inlet near Beluga. What are the alternative siting locations, layout and configurations (nearshore, offshore, dredging, etc.)?	The Applicant will address this comment prior to the initiation of the EIS process.

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EPA	9/30/2016	Temporary Material Offloading Facility (MOF) - On-site MOF Configuration – The Nearshore MOF includes a proposed dredging channel and allows vessels to stay floating while they are offloaded, was selected as the preferred alternative. We recommend including additional information regarding the dredging requirements for the MOF. What are the dimensions of the dredge channel (e.g., depth, top and bottom width); area (acres); volume of dredged material (cubic yards); season of dredging (winter or summer); methods of dredging (clamshell, hopper, suction, etc.); the frequency and volume of maintenance dredging, location of the dredged channel, etc. We recommend including an alternatives analysis of the dredge channel locations and size, and methods of dredging. We recommend a bathymetric map that includes the location of the MOF and the alternative locations and areas of the dredge channel should be included in the Reports.	The Applicant will address this comment after the DEIS but prior to the issuance of the FEIS.
EPA	9/30/2016	Facility Energy Needs (LNG Plant) – We recommend evaluating all facilities and equipment energy needs during construction and operations of the LNG Plant. We recommend an alternatives analysis using cleaner burning energy sources, such as LNG and/or natural gas to power heavy construction equipment, dredgers, vehicles, trucks, barges, and LNG container carriers, etc. rather than diesel fuel.	The Applicant will address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	Trestle Support Design - Resource Report No. 10 (P. 10-255) indicates that the Kenai Peninsula bluff erodes at a rate of 3 to 6 feet per year. In the Project vicinity, the rates of retreat have been documented to be greater than 2 feet per year. How will the marine terminal trestle be protected against bluff erosion? Are there plans to install a hardened structure along the bluff to prevent/minimize erosion? The marine terminal at the ConocoPhillips LNG facility is supported by a hardened structure along the toe of the bluff.	The Applicant will address this comment after the DEIS but prior to the issuance of the FEIS.
EPA	9/30/2016	Alaska Stand Alone Pipeline (ASAP) Project - We understand that AGDC may be assuming leadership of the AK LNG Project. If so, the Corporation would be the Project proponent for both the AK LNG Project and the smaller diameter in-state Alaska Stand Alone Pipeline (ASAP) Project. To maximize efficiency, we recommend that the planning and environmental review procedures for both the AK LNG Project and the ASAP Project be integrated into a single comprehensive EIS. We believe that such an approach would reduce delay, duplication, and paperwork. This could be accomplished by broadening the Purpose and Need Statement and/or including the ASAP Project as an action alternative in the AK LNG Project EIS.	Comment acknowledged.
EPA	9/30/2016	Greenfield vs. Collocation - The Reports indicate that the Mainline is collocated for approximately 36 percent of the route. We recommend that the Reports provide a detailed comparative analysis of environmental impacts between the greenfield versus collocated routes. In particular, the portion from Livengood to Nenana, west side of Susitna River, and the Kenai Peninsula should be evaluated since the pipeline would not parallel existing corridors.	The Project follows existing linear features to the extent practicable as discussed in Section 10.4.2.2 of this resource report.
EPA	9/30/2016	Denali National Park and Preserve (DNPP) - The DNPP minor route variation may require additional aboveground and/or below ground facilities, such as, but not limited to, compressor, heater, and meter stations, mainline block valves, cathodic protection	It is not currently anticipated that the DNPP minor route variation would require additional aboveground

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		facilities, pig launcher/receiver stations, communication and electric cables, temporary and/or permanent access roads, camps, pipe storage areas, contractor yards, rail spurs, fuels storage facilities, and construction infrastructure, temporary work and storage pad areas within the Park. We recommend that the Reports discuss these aboveground and/or below ground appurtenances, identify them on aerial maps, and evaluate their direct, indirect, and cumulative impacts.	and/or below ground facilities.
EPA	9/30/2016	Infrastructure Improvements - The DNPP route variation would enter the DNPP along the George Parks Highway after crossing the Nenana River. There is existing surface infrastructure near the vicinity of the Park, such as the Highway, the Alaska Rail Road, a highway and footbridge, recreation hiking and bike trails, the Park Road, etc. As part of the logistics planning for the DNPP route variation, there may be a need to upgrade/improve the existing surface infrastructure. We recommend that the Reports evaluate the need to upgrade/improve existing infrastructure for the DNPP route variation as connected actions or actions pertaining to this project. The Reports should evaluate the direct, indirect, and cumulative impacts associated with these infrastructure improvements.	Currently there are no plans required to update the infrastructure since the Project will work within the load limitations of the infrastructure.
EPA	9/30/2016	Section 11 of the Alaska Statehood Act indicates that the US, apart from limited exceptions not relevant here, shall exercise exclusive jurisdiction in the Park. We note that the DNPP route variation through the Park would potentially trigger EPA's regulatory authorities. For example, EPA retains CWA Section 402 National Pollutant Discharge Elimination System (NPDES) and Section 401 Water Quality Certification authority within the Park based on Section 11 of the Alaska Statehood Act, and as set forth in the related Memorandum of Agreement between EPA and State of Alaska. (See National Pollutant Discharge Elimination System Memorandum of Agreement between State of Alaska and U.S. EPA (2008) at §§ 3.01, 3.03, and 4.14.) The CWA Section 402 NPDES requirements may apply to any discharge of pollutants associated with the following activities within the Park boundaries, such as construction storm water, hydrostatic testing, camp domestic wastewater, filter backwash, gravel pit and excavation dewatering, fire testing, secondary containment, mobile spill response, horizontal directional drilling, non-contact cooling water, and other related activities. A CWA Section 401 Water Quality Certification is required for certain activities authorized under other federal permits, such as permits issued by the Corps of Engineers under Section 404 of the CWA. Depending on the specific nature of project-related activities that would occur within the Park, other EPA authorities may similarly apply. As a cooperating agency, EPA will continue to work closely with FERC and the Project proponent to identify applicable EPA authorities once the formal application has been filed and the environmental analysis is further developed.	Comment acknowledged.
EPA	9/30/2016	The DNPP minor route variation would impact public federal lands managed by the Department of Interior, National Park Service. The Park is managed under a consolidated General Management Plan (1986) with several major amendments including the Entrance Area and Road Corridor Development Concept Plan (1997), the South Side Development Concept Plan (1997), and the Backcountry Management Plan (2006). The Reports should evaluate and discuss how the DNPP route variation would be	Legislation passed by Congress (Public Law 113-33) permits a high pressure natural gas transmission pipeline in non-wilderness areas of the Park. This Public Law supersedes compatibility with the

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		consistent or inconsistent with the existing federal management plans for the Park. We recommend that the Reports identify mitigation measures to avoid and minimize potential adverse impacts to federal public lands and ensure consistency with the Park General Management Plans. EPA notes that the Park General Management Plan and amendments may require updating to ensure that the DNPP route variation is consistent with plan requirements and to address the potential induced growth and future indirect land development, and the other reasonably foreseeable future actions both within and directly outside of the Park boundaries. Updates and amendments to the General Management Plan would ensure compatible uses between the AK LNG Project mainline pipeline and the resources, visitors, recreation, and general development of the Park.	DNPP's Consolidated General Management Plan.
EPA	9/30/2016	Recreation Impacts - The construction and operation of a DNPP route variation near the Park entrance and visitor center may impact recreational facilities and activities. There are a number of hiking trails, bicycle paths, camping sites within the proposed alignment of the DNPP Alternative. The Nenana River forms the eastern boundary of the Park and is a popular area for recreational boating and white water rafting activities during the summer season. We recommend that the Reports evaluate the direct, indirect, and cumulative impacts to recreational facilities and activities within and adjacent to the Park as a result of the DNPP route variation.	This route alternative is not the proposed route and no additional study is proposed on this alternative.
EPA	9/30/2016	Water Resources - A number of waterbody crossings would be required for the DNPP route variation. The Reports should identify the location of the waterbody crossings, such as rivers, streams, lakes, wetlands, etc. within and adjacent to the Park. The Reports describes the construction methods for the DNPP route variation waterbody crossings, such as open trench, horizontal directional drilling, aerial crossing, etc. The Reports should evaluate the direct, indirect, and cumulative impacts associated with the waterbody crossing construction techniques. In particular, the Nenana River is a major waterbody that would be crossed by the DNPP route variation. There is an existing footbridge and the George Parks Highway bridge over the Nenana River north of the Park entrance. We recommend that the Reports consider a pipeline crossing the Nenana River suspended from one of these existing bridges in order to avoid construction impacts to the river. The DNPP route variation may require large volumes of freshwater for project construction, hydrostatic testing, etc. We recommend the Reports identify the location of water resources for water withdrawal within and adjacent to the Park. Each water resource should be evaluated for the volume (gallons) to be withdrawn, depth, and presence/absence of resident and/or anadromous fish. We recommend that the Reports identify mitigation measures to avoid and minimize potential impacts to fisheries. We recommend that the Reports identify the location of water resources where waste water would be discharged from certain activities, such as hydrostatic testing, construction storm water, etc. that may be subject to CWA permitting requirements. We recommend that the Reports evaluate the direct, indirect, and cumulative impacts associated with the discharges of wastewater into water resources within and outside the Park boundaries.	This route alternative is not the proposed route and no additional study is proposed on this alternative.
EPA	9/30/2016	Material Source Sites - The construction of the DNPP route variation may require large volumes of gravel material for	FERC will prepare the EIS that addresses direct,

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		permanent and temporary access roads, pads, and other project related facilities. We recommend that the Reports identify the location of the material source site within and adjacent to the Park. For each material source site, the Reports should include estimates of the surface area impacts (acres), volume of material available (cubic yards), and describe how these material source sites would be restored and rehabilitated at the end of each site's active life. We recommend that the Reports evaluate the direct, indirect, and cumulative impacts associated with the development of the material source sites to cultural and historic resources, wetlands, recreation, and other resources.	indirect, and cumulative impacts based on their requirements.
EPA	9/30/2016	Induced Growth/Indirect Land Use Effects - The DNPP route variation would result in induced growth and indirect land use effects associated with the pipeline construction and operation. A source of natural gas to the Park may result in future development of ancillary natural gas distribution systems within and adjacent to the Park boundary. Reasonably foreseeable future actions could include additional public access, roads, infrastructure, lodging, hiking trails and bike paths, public facilities, etc. in and around the vicinity of the Park. The Reports should evaluate the potential impacts of the indirect and cumulative effects from induced growth and changes in land use in and outside to the Park boundaries, such as the McKinley Park Village and the overall socioeconomic impacts. We recommend that the Reports evaluate the potential increase in the number of visitors to the Park, the need for additional public and recreational services and facilities, and the use of existing roads and railroads to access the Park.	The Applicant will address this comment prior to the initiation of the EIS process.
EPA	9/30/2016	Fairbanks Route Variation - The Reports should include additional information regarding collocating the mainline pipeline with the Elliott and Parks Highway. The discussion should include how the Fairbanks Route Variation would improve construction and operations/maintenance of the mainline pipeline. We recommend collocating the pipeline with existing infrastructure to improve the practicability of construction and avoid the need for new access roads and impacts to greenfields, even though the Fairbanks Route Variation is 37 miles longer.	See Section 10.4.4.2.
EPA	9/30/2016	Route Revision B (Proposed Alternative) - Table 10.4.4-3. We recommend that the summary of differences between Route Revision A and Route Revision B be provided for each of the 39 proposed minor route revisions and not just as a summary of the entire route revisions. This information should be included in Table 10.4.4-3 and with the corresponding figures in Appendix C. Route Refinement 24: MP 439.05 to 442.74 (3.46 miles) a reduction in 0.22 miles. Rationale: route to shorten and straighten the route within the Minto Flats SGR. The previous Route Revision A avoided and minimized impacts to wetlands. This route was on a higher and dryer area that would appear to be more technically, logistically, and economically feasible (practicable) under the Clean Water Act Section 404(b)(1) Guidelines. The proposed Revision B route would be shorter by 0.22 miles, but would result in greater impacts to wetlands. In Report No. 4, Cultural Resources, there is the potential of culturally important areas near the Minto Flats, including archaeological sites and deeply buried cultural deposits in several locations. We recommend that these cultural and archaeological sites should be factored into revising the mainline pipeline route to avoid these important resources near the Minto Flats.	This is a common way to examine minor route variations for a large-scale project.

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EPA	9/30/2016	Aboveground versus Belowground Pipeline Design – We recommend evaluation of an aboveground natural gas pipeline on VSMs for the first few miles on the Arctic Coastal Plain. The Reports should include consideration of the challenges and costs of tundra wetlands restoration. There are examples where restoring tundra wetlands from decommissioned oil and gas infrastructure on the North Slope have failed. The slow development of tundra wetlands on the North Slope makes restoration that much more difficult. The placement of VSMs on the tundra would not require tundra wetlands restoration.	See Section 10.4.5.1 for further explanation of why the Mainline needs to be buried.
EPA	9/30/2016	PTTL - We concur with the PTTL aboveground design on VSMs. We recommend that the Reports evaluate the coating design of the PTTL aboveground pipeline. Based on TEK, the color and sheen of the outer coating of the aboveground pipeline is a consideration for subsistence hunters on the North Slope. This may affect subsistence hunters' ability to visually observe wildlife movement in the horizon against the sunlight, snow reflection, tundra, etc.	The Applicant will address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	Yukon River Crossing Design – We recommend that the Reports clarify that the trenchless installation includes either Horizontal Directional Drilling (HDD) or Direct Pipe	See Section 10.4.7.1.
EPA	9/30/2016	PTTL River Crossing – We recommend a more detailed analysis for the river crossing methods (e.g., open cut, trenchless or HDD, and pipe bridge, etc.) for the Shaviovik River, Kadleroshilik River, and the Sag River (mainline and west channel) in the Reports.	See Section 10.4.8 and Appendix E.
EPA	9/30/2016	Facility Supply Alternatives (GTP) – We recommend evaluating all facilities and equipment energy needs during construction and operations of the GTP. We recommend including an alternatives analysis of cleaner burning energy sources, such as LNG and/or natural gas to power heavy construction equipment, dredgers, vehicles, trucks, barges, etc.	See Section 9.2.7 of Resource Report No. 9
EPA	9/30/2016	Marine Pipeline Installation and Burial Alternatives – We recommend including a diagram or rendering depicting the marine pipeline burial methods in the Reports. This may be useful for public understanding.	The Applicant will address this comment prior to the initiation of the EIS process.
EPA	9/30/2016	HDD – a description of HDD method of installation is found in Section 10.5.2.3.3.1 of Resource Report No. 1… Should be Section 1.5.2.3.3.1.	See Section 10.6.2.3.
EPA	9/30/2016	Pressure Testing - The Report indicates that water is the proposed action for pressure testing during construction of the pipeline (on- and offshore), the LNG tanks, and other large volume testing requirements. We recommend that the Reports thoroughly evaluate the use of alternatives to water, such as inert gaseous medium (e.g., nitrogen, etc.). The discharge of hydrostatic test water would require additional CWA permitting and may result in potential adverse impacts to receiving waters. The use of alternative gaseous medium for pressure testing would avoid impacts to fish bearing waters.	The Applicant will address this comment prior to the initiation of the EIS process.
EPA	9/30/2016	Dredging Techniques Alternatives – We recommend including in the Reports a diagram or rending depicting the different dredging methods. This may be useful for public understanding.	The Applicant will address this comment prior to the issuance of the DEIS.
EPA	9/30/2016	Dredging Technique Alternatives - Has there been any dredging of test trenches in the Cook Inlet on the west side for the MOF near Beluga? What is the area (acres) and the location of the dredging	No test trenches have been conducted near the Mainline MOF, no dredging will be

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		area at the Beluga MOF? We recommend including a map depicting the location of the dredge area locations and alternative locations and configurations in Cook Inlet.	required there. Maps of Mainline MOF area are provided in Appendix A of Resource Report No. 1.
EPA	9/30/2016	Marine Terminal Dredged material disposal options - We recommend including a map depicting the locations of the proposed in water and/or nearshore disposal sites in Cook Inlet, the location of beneficial use areas, such as beach nourishment, shoreline stabilization, and erosion protection, fill for project development, upland areas, etc. We recommend that the Reports include evaluation of deep water disposal sites in lower Cook Inlet south of Kalgin Island, subject to MPRSA. We recommend that a Sampling and Analysis Plan be developed and included in the appendix of the Reports.	The Applicant will address this comment prior to the initiation of the EIS process.
EPA	9/30/2016	GTP West Dock – Dredge Material Placement Areas at Prudhoe Bay - As part of the alternatives analysis, we recommend that the Reports evaluate a disposal site outside of Prudhoe Bay, in deeper waters, subject to MPRSA. We recommend that a Sampling and Analysis Plan be developed and included in the appendix of the Reports.	See Section 1.4.2.4.2.3 of Resource Report No. 1. The proposed Dock Head 4 (DH 4) design does not require dredging.
KPB	10/5/2016	The borough urges the Project sponsor(s) and asks that FERC encourage the sponsor(s) to do the work necessary to at least narrow down the highway relocation options to three clearly delineated choices if not one preferred option identifying specific rights-of-way so that property owners can know whether they would be impacted by the reroute.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
KPB	10/5/2016	Though Alaska LNG has, in the past, done a good job of briefing and updating the Kenai Borough government and area residents of the highway relocation planning effort, those discussions have essentially ceased in recent months, and the silence is building to frustration among area residents. The borough urges whichever entity(ies) emerges as project sponsor(s) to actively resume those discussions with detailed mapping, detailed selection criteria and a commitment to narrowing down the options next year.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
KPB	10/5/2016	The borough's concern is that the Project's full application to FERC might take longer than anticipated, especially considering the shift in project leadership from Alaska LNG LLC to the State of Alaska. As such, the borough is concerned that the Kenai Spur Highway relocation work could be moved to the proverbial back burner in lieu of more pressing fiscal and political work on the Project development plan. The borough submits these comments to FERC in the interest of ensuring that the highway relocation selection process moves ahead in a timely manner, so as to limit the impact of uncertainty on property owners in the area.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. a. A figure showing Dock Head No. 4 configurations. (Agency Comments and Requests for Information Concerning General Project Description table, page 10-xi)	The Applicant will address this comment prior to the issuance of the DEIS.

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FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. b. We consider route segments greater than 500 feet from another linear facility's centerline to be greenfield segments. Include a summary of what alternatives were considered in these greenfield areas. The summary should include a comparison of the routes considered. Factors to include in the analysis are (Agency Comments and Requests for Information Concerning General Project Description table, page 10-xv): i. number of total miles crossed; ii. acres of construction right-of-way; iii. acres of permanent right-of-way; iv. number of waterbody crossings; v. acres of wetlands affected; vi. land ownership type; vii. land use types affected in acres; viii. reasons the alternative was dismissed as the planned route; and ix. any other factor needed to provide a meaningful analysis of the alternatives considered.	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. c. Additional information on the siting of the Coldfoot Compressor Station, including alternative sites considered and final noise modeling information. (Agency Comments and Requests for Information Concerning General Project Description table, page 10-xix)	See Section 10.4.9.1.2.
FERC	10/26/2016	Following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. d. Results of groundwater studies to further assess potential groundwater yield and potential impacts from long-term water withdrawal at the Liquefaction Facility site. (page 10-xxvii)	See Resource Report No. 2. The Applicant will further address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. e. Evaluation of the potential use of alternative nearby marine facilities to support construction activities and minimize dredging and construction impacts without impeding existing use of the facilities. (section 10.3.1.1.1, page 10-53)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. f. Evaluation of available mechanical drive natural gas turbine	The Applicant will address this comment prior to the initiation of the EIS process.

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Agency	Comment Date	Comment	Response/Resource Report Location
		models to determine the proposed models to drive refrigerant compression. (section 10.3.4.1.3.1, page 10-113)	
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. g. Additional analysis regarding route alternatives or variations for the Cook Inlet crossing, based on the Project's geophysical and geotechnical investigations. (section 10.4.3.2, page 10-142)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. h. A final assessment of the feasibility of using electric-motor-driven compressors in lieu of gas-fired turbines. (section 10.4.9.3, page 10-179)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. i. An assessment of the feasibility of utilizing smaller equipment delivery modules, for purposes of delivering material for GTP construction. (section 10.5.6, page 10-212).	See Section 10.5.6; the Project is examining the feasibility of using smaller modules than the sizes currently planned. More detailed engineering will be completed prior to construction.
FERC	10/26/2016	Following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. j. Additional information regarding in-fill rates for Dock Head No. 4 and additional alternatives associated with the dredging at Dock Head 4. (section 10.5.7.1, page 10-218)	See Section 1.4.2.4.2.3 of Resource Report No. 1. The proposed Dock Head 4 (DH 4) design does not require dredging.
FERC	10/26/2016	Following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. k. A decision on the pipelay construction methods across Cook Inlet subsequent to the Applicants' investigation of the geotechnical and geological conditions at each crossing. (section 10.6.2.3, page 10-236)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. l. Dredged material placement areas associated with the proposed West Dock modifications. (section 10.6.4.2.2, page 10-258)	See Section 1.4.2.4.2.3 of Resource Report No. 1. The proposed Dock Head 4 (DH 4) design does not require dredging.

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Agency	Comment Date	Comment	Response/Resource Report Location
FERC	10/26/2016	Following commitments were made by AKLNG in resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by AKLNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. m. Full evaluation of alternative dredge material placement sites. (section 10.6.4.2.2, page 10-260)	See Section 1.4.2.4.2.3 of Resource Report No. 1. The proposed Dock Head 4 (DH 4) design does not require dredging.
FERC	10/26/2016	1. The following commitments were made by Alaska LNG in the resource report as information to be provided or pending in response to previous comments made FERC or other agencies. If the information will not be included in the application as indicated by Alaska LNG, provide a schedule for when it will be filed with FERC or provided to the requesting agency as applicable. n. Siting information, alternatives, and analysis for construction camps, other facilities associated with construction, material sites, and water sources. (section 10.6.5, page 10-260; section 10.6.6, page 10-260; section 10.6.7, page 10-261)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	2. Include documented justification for the use of gravel fill along the right-of-way, including gravel pads and travel lanes. a. Include a robust discussion of its benefits, limitations, and options, including: i. an explanation of why is it necessary to use gravel fill for saturated terrain in Alaska, compared to other methods used in pipeline construction across saturated terrain in the lower 48 states; ii. an evaluation and comparison of other material options (e.g., wood chips, timber brought in from other parts of the Project for corduroy road or to create mats, low ground-weight equipment, or other lighter color materials with reflective properties to reflect solar energy); iii. a description of the source of the gravel fill; and iv. an analysis of restricting mainline pipeline construction across saturated terrain to periods of frozen soil conditions. Include a comparison of the approximate amounts of gravel fill that would be needed for winter construction versus summer construction. b. Address the regulatory and permitting requirements for importing such fill (both temporary and permanent) to wetlands.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	3. Include a table summarizing Project modifications that were adopted to minimize environmental impact or respond to a stakeholder issue.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	4. Include a map of the Anderson Bay Marine Terminal site, or modify figure B-22 showing where 39 million cubic yards of material that would need to be excavated at this site would be placed, and include a description of the fill's impacts on marine species and habitat. Clarify what, if any, permanent terminal facilities would need to be located on the fill area, and discuss seismic considerations associated with locating any permanent terminal facilities on the fill area.	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	5. Include a table comparing the three MOF options. (section 10.3.3.4.2, page 10-107) At a minimum, address the following: a. area of disturbance to sea-bed; b. dimensions of dredge channel (e.g. depth, top and bottom width); c. season of dredging; d. dredging method; e. frequency and volume of maintenance dredging; f. area of off-shore fill required; g. area of onshore ground disturbance, excluding access roads; h. onshore access road length (if differences exist); i. duration of offloading operations (total time or time per unit volume); and j. construction and operational constraints and considerations.	The Applicant will address this comment prior to the issuance of the DEIS.

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FERC	10/26/2016	6. In the "Summary of Filing Information" (p. 10-xvi), the Resource Report provides a brief explanation why it is not possible to reduce the number of Nenana River crossings. Include such a discussion in Resource Report 10. (section 10.4.2, page 10-126)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	7. Table 10.4.2.1 does not provide sufficient information for a comparative analysis of the greenfield segment with a non-greenfield alternative. For example, the fourth segment under "North Slope Borough" indicates that the rationale was to shorten the route and reduce environmental impacts, but provides no information allowing for a comparison between the proposed route and a non-greenfield alternative. Include tables for each of these segments for which there is a feasible non-greenfield alternative that compare the number of total miles crossed, acres of construction right-of-way, acres of permanent right-of-way, number of waterbody crossings, acres of wetlands affected, land ownership type, land use types affected in acres, and any other relevant factors. For any segments that have no feasible non-greenfield alternatives, include an explanation for why there are none. (section 10.4.2, page 10-133)	The Applicant will address this comment prior to the issuance of the DEIS.
FERC	10/26/2016	8. The comparison of the Fairbanks Route Variation with the Applicant's Route Revision B does not take into account that the alternative would eliminate the need to build a long lateral from the Fairbanks interconnect with the Applicants' Project. Incorporate that factor into the comparative analysis. (section 10.4.2.3, page 10-134)	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	9. Supplement table 10.3.2.4 with a table comparing the pipeline elements of the Valdez Delivery Option with those of the planned Project. Include at a minimum the following factors in the comparative analysis: a. length (miles); b. collocation, i.e. within 500 feet of centerline (miles); c. visual resources; d. active fault crossings; e. land use types (miles); f. land ownership, i.e. public (by land managing agency), native lands, private (miles); g. residences within 200 feet of centerline; h. wetland crossings (miles); i. stream crossings >100 feet wide (number); j. wild and Scenic River crossings (number); k. designated critical habitat ; l. essential fish habitat; m. AHRS sites (number of sites crossed, number within 2,000 feet); n. contamination areas within 1,000 feet of centerline (number); o. practicability of construction; p. new access roads (miles); and q. compressor stations (number).	See revised Section 10.4.3.1.
FERC	10/26/2016	10. Include a discussion of whether and how the crossings of the Gulkana and Delta Rivers would conflict with the values associated with the Wild and Scenic River designations for these two streams, and how any such conflicts could be mitigated.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	11. Identify where the TAPS route alternative would cross a National Forest. Include information about the National Forest management plan objectives for the alternative pipeline corridor, including whether a pipeline would be consistent with the National Forest management objectives. Identify specific locations where the pipeline would not be consistent with management objectives. Include comparative detail regarding the authorization process, which appears to be similar to that required for the proposed route, given the BLM's role in issuing Temporary Use Permits and the Right-of-Way Grant per the Mineral Leasing Act of 1920 and the Federal Land Policy and Management Act.	.The Applicant will address this comment prior to the initiation of the EIS process.

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FERC	10/26/2016	12. The proposed route traverses areas that appear to have no existing infrastructure (roads, railroad, material source sites, airstrips, etc.) to support construction of the pipeline. The Applicants propose to build infrastructure that would open up undeveloped areas to the greater public. In addition to environmental impacts, address the potential for longer duration and higher costs associated with developing infrastructure to support the pipeline construction and operation in these areas relative to the alternatives. Include this analysis for the Fairbanks alternative route compared to the MP 405 to MP 439 segment, as well as for the east route depicted in figure 10.4.3-1 compared to the MP 674 to MP 792.	.The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	13. Include a discussion that specifies how application of Alaska National Interest Lands Conservation Act to the entire Project would prohibit realization of the Project purpose.	See Applicant response to scoping comments posted to the FERC Docket on 11/15/2016 (Accession No. 20161115-5014).
FERC	10/26/2016	14. Include a discussion of whether the DNPP Alternative would be consistent with the DNPP's Consolidated General Management Plan or other relevant Park management plans.	Legislation passed by Congress (Public Law 113-33) permits a high pressure natural gas transmission pipeline in non-wilderness areas of the Park. This Public Law supersedes compatibility with the DNPP's Consolidated General Management Plan.
FERC	10/26/2016	15. In support of further analysis of the DNPP Alternative, and to address comments received during the supplemental scoping period, conduct field surveys for comparison with data collected with the corresponding segment of the proposed route. An equivalent level of data should be collected for biological resources, wetlands, waterbodies, and visual resources, as well as geotechnical evaluations at fault crossings and to inform proposed waterbody crossing methods as applicable. In addition, conduct a literature review and cultural resources field survey of the DNPP Alternative. The comparison should include the total number of cultural resources previously recorded and newly identified within the APE of both segments, the number of potentially eligible sites, and the number of potentially eligible sites that will be avoided.	Field studies are not conducted for alternatives that are not the preferred.
FERC	10/26/2016	16. Include a comparative analysis of the proposed route, DNPP Alternative, and a DNPP Alternative that follows the George Parks Highway from Glitter Gulch to Carlo Creek. The analysis should address visual impacts as well as comparison of the following factors: a. length (miles); b. collocation, i.e. within 500 feet of centerline (miles); c. visual resources: d. active fault crossings; e. land use types (miles); f. land ownership; g. residences within 200 feet of centerline; h. wetland crossings (miles); i. stream crossings >100 feet wide (number); j. contamination areas within 1,000 feet of centerline (number); k. practicability of construction; l. new access roads (miles); and m. AHRS sites (number of sites crossed, number within 2,000 feet; percentage of route surveyed for cultural resources).	See updated Table 10.4.4-1.
FERC	10/26/2016	17. Include a discussion of the feasibility of crossing the Nenana River on the DNPP Alternative by suspending the pipeline on	See Section 10.4.4.1.

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		George Park Highway Bridge or a nearby existing footbridge, north of the Park entrance.	
FERC	10/26/2016	18. Indicate whether the likely crossing method for the Nenana River on the DNPP Alternative would differ from the crossing of the same river by the planned Project.	See Section 10.4.4.1.
FERC	10/26/2016	19. Indicate whether, and how, the volumes and sources of gravel utilized for the DNPP Alternative would differ from that for the planned Project segment it would replace.	See Section 10.4.4.1.
FERC	10/26/2016	20. Include a comparison of impacts on recreational activities and tourism associated with the DNPP in comparison with the segment of the planned Project it would replace.	This route alternative is not the proposed route and no additional study is proposed on this alternative.
FERC	10/26/2016	21. Discuss the issue of ground subsidence over the mainline, and associated environmental impacts, in the context of comparing the proposed belowground design vs. the aboveground alternative.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	22. Include an analysis for a compressor station site farther from Coldfoot than the proposed Coldfoot Compressor Station (Station 6), aimed at reducing noise impacts.	See Section 10.4.9.1.2.
FERC	10/26/2016	23. Include the results of the study evaluating the feasibility of using electric-motor- driven compressors at the compressor stations, as well as the feasibility of using electric power from the existing power transmission and distribution network to feed power demand at the pipeline facilities.	See section 10.4.9.3
FERC	10/26/2016	24. Explain why a reservoir along the Sagavanirktok River should not be considered the least environmentally damaging practicable alternative for sourcing water for the proposed GTP's annual water needs. Include a detailed analysis comparing technical issues and environmental impacts of this alternative with the proposed action.	A comparison of water sources was assessed in Resource Report No. 10. See Table 10.5.3-1 and Section 10.5.4.3 for additional information on why the preferred alternative is the least damaging practicable alternative.
FERC	10/26/2016	25. Include a figure showing the proposed and alternative configurations for Dock Head 4.	See Figure 10.5.7-2.
FERC	10/26/2016	26. Include a comparative estimate of air pollutant emissions from the Dynamically Positioned (DP) Lay Vessel with Anchor Moorings (Applicants' Proposed Alternative), and the Conventionally Moored Lay Vessel Alternative.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	27. Include a comparative estimate of noise levels (i.e. intensities and durations) from the DP Lay Vessel with Anchor Moorings (Applicants' Proposed Alternative), and the Conventionally Moored Lay Vessel Alternative.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	28. Include the basis for the statement that the preferred DP lay barge method may require an incidental harassment authorization from NMFS, while a conventional mooring system probably would not; include any correspondence with the NMFS regarding the matter.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	29. With respect to the Direct Pipe alternative for the Cook Inlet shore crossing, include the length limitations for microtunneling, which is alluded to in table 10.6.2-3.	The Applicant will address this comment prior to the initiation of the EIS process.

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Agency	Comment Date	Comment	Response/Resource Report Location
FERC	10/26/2016	30. Table 10.6.2.3 is ambiguous regarding whether an offshore jack-up vessel would be necessary for the HDD, stating that it would be required, but also suggesting that it may not be. Clarify whether it would be required, and what other option(s) might be considered.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	31. For the direct lay of the marine segment, include evidence of consultation with the U.S. Department of Transportation that use of the direct lay would meet the requirements of the U.S. Department of Transportation's Minimum Federal Safety Standards in 49 CFR 192.	The Applicant will address this comment prior to the initiation of the EIS process.
FERC	10/26/2016	32. Include an explanation for why air testing is "not feasible" as an alternative to hydrostatic testing on mainline pipe segments.	See Section 10.6.3.
FERC	10/26/2016	1. Include information regarding the considerations and relative impacts associated with alternative sources of gravel, alternative water sources, and work camp alternatives. (sections 10.6.5, 10.6.6, and 10.6.7, pages 10-260 and 10-261)	The Applicant will address this comment prior to the initiation of the EIS process.
NPS	9/26/2016	Any proposed route that would cross Denali NP lands would need to be surveyed for cultural resources using the same methodology outlined in chapter 4.	Comment acknowledged. The proposed route does not cross Denali NP lands.
SOA / ADNR / SPCS	9/25/2016	General comment- there is a second smaller bridge just north of Dock Head 3 (120 ft.) that is not addressed in this section. How does the Project propose to move the modules past this bridge if they utilize the proposed Dock Head 4?	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
SOA / ADNR / DGGS / Engineering Geology	9/25/2016	First two lines should refer to a snow avalanche (not a landslide) that occurred in 2014 and closed the road.	The Applicant will address State of Alaska agency comments during the State permitting processes and timeframes.
USACE	9/26/2016	13. Specific to RR10 – Alternatives, Both ASAP and Alaska LNG should be addressed within the Alaska LNG EIS. Although ASAP does not have an export component as a connected action it is a reasonably foreseeable action with a separate entity (REI) constructing an LNG facility for export on the north side of Cook Inlet.	ASAP has a different purpose and need than Alaska LNG, the designs, facilities, and routes are different.
USFWS	9/26/2016	The Service continues to have concerns about the proposal to bury long lengths of the gas pipeline on the ACP. We believe there is high potential for thermokarst and subsidence over the buried pipeline. Disturbance of the active layer and the upper portion of the permafrost layer through compaction or removal at any time of the year destroys the thermal insulation and exposes the upper layers of permafrost soil to increased temperatures, resulting in thermokarst and subsidence during the summer. The subsidence of the overlaying soils will occur regardless if the pipeline is chilled or not. Once this disturbance has been created and subsidence occurs, the process becomes very difficult, if not impossible, to amend. Climate change, with increased temperatures and longer periods of thaw, likely will exacerbate the occurrence of subsidence due to thermokarst on the ACP. Maintaining the integrity of the active layer and the underlying permanently frozen soils therefore is critically important, especially as regard to construction and maintenance of infrastructure on the ACP.	The Applicant will address this comment prior to the issuance of the DEIS.

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USFWS	9/26/2016	The Service supports the proposal for an elevated pipeline from Point Thomson to the Gas Treatment Plant, however we have significant concerns with the proposal to trench the pipeline through river crossings along this route or on the ACP in general. We recommend the entire Point Thomson pipeline, including all river crossings, be elevated at least 7 feet above-ground on VSMs. On the ACP, bisecting a river bank with a trench can cause the bank to erode through thermokarst, with potential to drain adjacent wetlands. Once this erosion process begins it is very difficult to remedy. The tranched Badami pipeline crossing of the east channel of the Sagavanirktok River is an example of the erosion and habitat degradation that can occur due to river bank erosion	See Appendix E for an evaluation of different river crossing designs.
USFWS	9/26/2016	We would like to see an alternative for the PTTL to include an above-ground (VSM-supported) transit of the pipeline for the entire length from PT to the GTP. There is no reason given as to why trench trenching the pipeline through the rivers is part of the above-ground (preferred) alternative. Other pipelines in the oil fields cross rivers on VSMs with the exception of the Colville River crossing of the Sales Line which is an HDD crossing (not trenched). While we do not suggest HDD crossings of these rivers, we also do not support trenched crossings of the PTTL. Trenching the pipeline through the rivers can induce erosion of the banks associated with the trench which may lead to draining of adjacent wetlands. Once the erosion occurs, it is difficult, if not impossible to abate. The trench will continue to be vulnerable to erosion with warming temperatures and increased flood events on the rivers. Elevating the PTTL on VSMs for its entire length also will alleviate the need for constant inspection and likely costly maintenance of the crossings.	See Appendix E for an evaluation of different river crossing designs.
USFWS	9/26/2016	The Service recommends the mainline not be buried on the ACP. Burying/trenching the mainline through the tundra from the Central Gas Facility south through the Arctic Coastal Plain also will result in subsidence over the pipeline. Once the tundra and underlying soil is disturbed via trenching the soil will become aeriated. Once the soil is placed back in the trench subsidence will occur, allowing water to pond and further infiltrate into the soil during spring/summer thaw. This will cause further subsidence. Once this process of subsidence and ponding begins it is nearly impossible to rectify. It is the disturbance of the soils above the pipeline during trenching that causes the soils to subside. Cooling the pipeline will not abate the problem as the pipeline itself is not the cause of the subsidence. Once subsidence occurs, water will pond along the trench and may cause adjacent wetlands to drain into the trench. In addition, sheetflow during spring break-up on the ACP tends to flow northward. As the pipeline in oriented in a North/South direction, the trench could become a conduit for water during breakup, potentially exacerbating erosion and drainage of adjacent wetlands. For these reasons, the Service strongly recommends the mainline be elevated on VSMs on the ACP. The elevation of the pipeline on VSMs through the ACP also would reduce the amount of gravel needed for construction along this section of the mainline, thereby greatly reducing the costs associated with mine sites development and gravel hauling. If, on the ACP, the proposed mainline ROW runs through an area underlain by thaw-stable soils (gravel soils associated with the Sagavanirktok River historic floodplain) trenching might be possible. The TAPS line is buried in these types of soils along	See Section 10.4.5.1.

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		portions of the Sagavanirktok River corridor. However, the proposed LNG ROW corridor is located to the west of the TAPS line and it is not known how far to the west the historic Sagavanirktok River flood plain (and hence the thaw-stable soils) extends. If FERC is determined to bury the mainline through ice-rich tundra soils on the ACP, the Service suggests extensive trials be conducted to prove the efficacy of their proposed technique. These trials should replicate the proposed methodology including sufficiently-long chilled pipelines buried through representative soils/wetlands to the same proposed depth and using the same techniques as proposed for the mainline. The trials should be conducted and monitored over a several year period. In the absence of these trials, the Service suggests elevating the gas pipeline on VSMs until thaw-stable soils are encountered south of the Arctic Coastal Plain. We suggest FERC develop an alternative encompassing a combination of an above-ground mainline (VSM-supported) on the ACP (30 to 60 miles) and a mostly-trenched mainline (where practicable) for the remainder of the route.	

Resource Report No. 10
Public Comments

Date	Individual/ Organization	Comment	Response/Resource Report Location
9/29/2016	McKay, Peter	DRR No. 10 Alternatives. Section 10.4.2.3 Mainline. On page 10-142 there is a discussion of a Suneva Lake Option “C”. This approach to the Nikiski pipeline landing has sub-sea approach features that make it attractive relative to Boulder Point. “A minor deviation is being considered that would span from the Viapan to Suneva Lake areas, herein referred to as the West Route Option”. If this route is selected then the discussion about preferable alternatives in the preceding paragraph may not be true. The rational # 4 “Avoids shore fishery leases” may not be true (on the Suneva Lake side there is a set-net site that would likely be impacted). Also the tally below “In comparison to the West Route, the East Route Option: Bullet no. 4 “Requires crossing one shore fishery lease that the West Route avoids.” would have to be struck. Table 10.4.3-1 Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives on page 10- 146 would need revision. Shore Fishery Leases and Tital Elements Crossings – Number of Fishery Leases (miles) the West Alternative should be revised from 0 to 1. (I don't know the distance of the lease but I would estimate the distance between sets at ½ mile). Waterbody Crossings (Other than Cook Inlet) the West Route Alternative should be revised from 33 to 34 as there would be an additional stream crossing for the outlet of Suneva Lake which drains to Cook Inlet. Roadway Crossings – would need to be revised as “Sockeye Ave” would need to be crossed.	The Applicant will address this comment prior to the initiation of the EIS process.
9/29/2016	McKay, Peter	DRR No. 10 Alternatives Section 10.6.2.3 Cook Inlet Shoreline Crossing Alternatives discusses factors that constrain pipeline installation options. As described the preferred shore crossing method is Open- Cut Trench. There is clearly a large volume of material that will need to be removed to cut back the (apx 80') bluff. The restoration of this will be a major undertaking. The discussion about the two possible alternatives for the nearshore pipeline pull points 1) pulling pipe from offshore to the bluff, or 2) possible pull the pipe from the bluff to the sea does not land on a clear preference and ultimately this decision is not clear at this time. Again this is disconcerting that this level of detail is not available for this important piece of work. I hope this is sorted out in the next revision.	The Applicant will address this comment prior to the initiation of the EIS process.

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ACRONYMS AND ABBREVIATIONS

ABBREVIATION	DEFINITION
Abbreviations for Units of Measurement	
dB	decibel
°F	degrees Fahrenheit
MMSCF/D	million standard cubic feet per day
MMTPA	million metric tons per annum
psig	pounds per square inch gauge
Other Abbreviations	
§	section or paragraph
AC	Alternating Current
ACEC	Areas of Critical Environmental Concern
ADEC	Alaska Department of Environmental Conservation
ADF&G	Alaska Department of Fish and Game
ADHSS	Alaska Department of Health and Social Services
ADNR	Alaska Department of Natural Resources
ADOT&PF	Alaska Department of Transportation and Public Facilities
AGDC	Alaska Gasline Development Corporation
AGI	Apex Gas Injection
AGPPT	Alaska Gas Producers Pipeline Team
AHRS	Alaska Heritage Resources Survey
ANGPA	Alaska Natural Gas Pipeline Act
ANGTS	Alaska Natural Gas Transportation System
ANILCA	Alaska National Interest Lands Conservation Act
APP	Alaska Pipeline Project
Applicant	The Alaska Gasline Development Corporation
ASAP	Alaska Stand Alone Pipeline
ASTER	Advanced Spaceborn Thermal Emission and Reflection Radiometer
B.C.	British Columbia
BACT	Best Available Control Technology
BLM	United States Department of the Interior, Bureau of Land Management
BMP	best management practice
BOG	boil-off gas
C3MR	Propane Pre-Cooled Mixed Refrigerant Process
C.F.R.	Code of Federal Regulations
CGF	Central Gas Facility
CH	Critical Habitat
CHA	Critical Habitat Area (managed by the State of Alaska)
CHP	Combined Heat and Power
CIRI	Cook Inlet Region, Incorporated
CO_2	carbon dioxide
CWA	Clean Water Act

ABBREVIATION	DEFINITION
DC	Direct Current
DGGS	Alaska Department of Natural Resources, Division of Geological and Geophysical Surveys
DH	dock head
DLN	Dry Low nitrogen oxides (NO_x)
DMR	dual-mixed refrigerant
DMLW	Alaska Department of Natural Resources, Division of Mining, Land, and Water
DNPP	Denali National Park and Preserve
DOE	United States Department of Energy
DOT	United States Department of Transportation
DP	dynamically positioned
EFH	Essential Fish Habitat
eGTP	electric gas treatment plant
EIS	Environmental Impact Statement
eLNG	all-electric LNG
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FEIS	Final Environmental Impact Statement
FERC	United States Department of Energy, Federal Energy Regulatory Commission
FTA	Free Trade Agreement
GHG	greenhouse gas
GIS	geographic information system
GPS	geographic positioning system
GTP	gas treatment plant
GVEA	Golden Valley Electric Association
HDD	horizontal directional drill
HEA	Homer Electric Association
H_2S	hydrogen sulfide
ISO	International Standards Organization
KPB	Kenai Peninsula Borough
kV	kilovolt
LEDPA	Least Environmentally Damaging Practicable Alternative
LiDAR	light detection and ranging
Liquefaction Facility	natural gas liquefaction facility
LLC	Limited Liability Company
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
Lo-Lo	Lift-on/Lift-off
LP	low pressure
LUST	leaking underground storage tanks
Mainline	An approximately 807-mile-long, large-diameter gas pipeline
MAOP	maximum allowable operating pressure
MEA	Matanuska Electric Association

ABBREVIATION	DEFINITION
MLBV	Mainline block valve
MLLW	mean lower low water
MOF	Material Offloading Facility
MP	Mainline milepost
MW	megawatt
NASA	National Aeronautics and Space Administration
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NHPA	National Historic Preservation Act
NMFS	National Oceanic and Atmospheric Administration, National Marine Fisheries Service
NO_X	nitrogen oxides
NO_2	nitrogen dioxide
NOAA	National Oceanographic and Atmospheric Administration
NPS	United States Department of the Interior, National Park Service
NRC	Natural Resources Canada
NRHP	National Register of Historic Places
NSA	Noise-Sensitive Area
NSB	North Slope Borough
NWI	National Wetlands Inventory
NWR	National Wildlife Refuge
OPMP	Alaska Department of Natural Resources Office of Project Management and Permitting
PBTL	Prudhoe Bay Gas Transmission Line
PBU	Prudhoe Bay Unit
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
PLF	Product Loading Facility
$PM_{2.5}$	particulate matter having an aerodynamic diameter of 2.5 microns or less
Project	Alaska LNG Project
PSD	Prevention of Significant Deterioration
PTTL	Point Thomson Gas Transmission Line
PTU	Point Thomson Unit
Put-23	Putuligayuk-23 mine site
Ro-Ro	Roll-on/Roll-off
ROW	right-of-way
SA-10	Service Area 10
SEIS	Supplemental Environmental Impact Statement
SGR	State Game Refuge
SHPO	State Historic Preservation Office(r)
SMIC	Seward Marine Industrial Center
SPCS	State Pipeline Coordinator's Section
SPMT	self-propelled module transporter

ABBREVIATION	DEFINITION
SRA	State Recreation Area
STP	Saltwater Treatment Plant
SWAPA	Southwest Alaska Pilots Association
TAGS	Trans-Alaska Gas System
TAPS	Trans-Alaska Pipeline System
U.S.	United States
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USFWS	United States Department of the Interior, Fish and Wildlife Service
USGS	United States Department of the Interior, United States Geological Survey
VMT	Valdez Marine Terminal
VSM	vertical support member
WHRU	waste heat recovery unit
WSA	Waterway Suitability Assessment

10.0 RESOURCE REPORT NO. 10 – ALTERNATIVES

10.1 PROJECT DESCRIPTION

The Alaska Gasline Development Corporation (Applicant) plans to construct one integrated liquefied natural gas (LNG) Project (Project) with interdependent facilities for the purpose of liquefying supplies of natural gas from Alaska, in particular from the Point Thomson Unit (PTU) and Prudhoe Bay Unit (PBU) production fields on the Alaska North Slope (North Slope), for export in foreign commerce and for in-state deliveries of natural gas.

The Natural Gas Act (NGA), 15 U.S.C. § 717a(11) (2006), and Federal Energy Regulatory Commission (FERC) regulations, 18 Code of Federal Regulations (C.F.R.) § 153.2(d) (2014), define "LNG terminal" to include "all natural gas facilities located onshore or in State waters that are used to receive, unload, load, store, transport, gasify, liquefy, or process natural gas that is ... exported to a foreign country from the United States." With respect to this Project, the "LNG Terminal" includes the following: a liquefaction facility (Liquefaction Facility) in Southcentral Alaska; an approximately 807-mile gas pipeline (Mainline); a gas treatment plant (GTP) within the PBU on the North Slope; an approximately 63-mile gas transmission line connecting the GTP to the PTU gas production facility (PTU Gas Transmission Line or PTTL); and an approximately 1-mile gas transmission line connecting the GTP to the PBU gas production facility (PBU Gas Transmission Line or PBTL). All of these facilities are essential to export natural gas in foreign commerce and will have a nominal design life of 30 years.

These components are shown in Resource Report No. 1, Figure 1.1-1, as well as the maps found in Appendices A and B of Resource Report No. 1. Their proposed basis for design is described as follows.

The new Liquefaction Facility would be constructed on the eastern shore of Cook Inlet just south of the existing Agrium fertilizer plant on the Kenai Peninsula, approximately 3 miles southwest of Nikiski and 8.5 miles north of Kenai. The Liquefaction Facility would include the structures, equipment, underlying access rights, and all other associated systems for final processing and liquefaction of natural gas, as well as storage and loading of LNG, including terminal facilities and auxiliary marine vessels used to support Marine Terminal operations (excluding LNG carriers [LNGCs]). The Liquefaction Facility would include three liquefaction trains combining to process up to approximately 20 million metric tons per annum (MMTPA) of LNG. Two 240,000-cubic-meter tanks would be constructed to store the LNG. The Liquefaction Facility would be capable of accommodating two LNGCs. The size of LNGCs that the Liquefaction Facility would accommodate would range between 125,000–216,000-cubic-meter vessels.

In addition to the Liquefaction Facility, the LNG Terminal would include the following interdependent facilities:

- Mainline: A new 42-inch-diameter natural gas pipeline approximately 807 miles in length would extend from the Liquefaction Facility to the GTP in the PBU, including the structures, equipment, and all other associated systems. The proposed design anticipates up to eight compressor stations; one standalone heater station, one heater station collocated with a compressor station, and six cooling stations associated with six of the compressor stations; four meter stations; 30 Mainline block valves (MLBVs); one pig launcher facility at the GTP meter station, one pig receiver facility at the Nikiski meter station, and combined pig launcher and receiver facilities at each of the compressor stations; and associated infrastructure facilities.

Associated infrastructure facilities would include additional temporary workspace (ATWS), access roads, helipads, construction camps, pipe storage areas, material extraction sites, and material disposal sites.

Along the Mainline route, there would be at least five gas interconnection points to allow for future in-state deliveries of natural gas. The approximate locations of three of the gas interconnection points have been tentatively identified as follows: milepost (MP) 441 to serve Fairbanks, MP 763 to serve the Matanuska-Susitna Valley and Anchorage, and MP 807 to serve the Kenai Peninsula. The size and location of the other interconnection points are unknown at this time. None of the potential third-party facilities used to condition, if required, or move natural gas away from these gas interconnection points are part of the Project. Potential third-party facilities are addressed in the Cumulative Impacts analysis found in Appendix L of Resource Report No. 1;

- GTP: A new GTP and associated facilities in the PBU would receive natural gas from the PBU Gas Transmission Line and the PTU Gas Transmission Line. The GTP would treat/process the natural gas for delivery into the Mainline. There would be custody transfer, verification, and process metering between the GTP and PBU for fuel gas, propane makeup, and byproducts. All of these would be on the GTP or PBU pads;
- PBU Gas Transmission Line: A new 60-inch natural gas transmission line would extend approximately 1 mile from the outlet flange of the PBU gas production facility to the inlet flange of the GTP. The PBU Gas Transmission Line would include one meter station on the GTP pad; and
- PTU Gas Transmission Line: A new 32-inch natural gas transmission line would extend approximately 63 miles from the outlet flange of the PTU gas production facility to the inlet flange of the GTP. The PTU Gas Transmission Line would include one meter station on the GTP pad, four MLBVs, and pig launcher and receiver facilities—one each at the PTU and GTP pads.

Existing State of Alaska transportation infrastructure would be used during the construction of these new facilities including ports, airports, roads, railroads, and airstrips (potentially including previously abandoned airstrips). A preliminary assessment of potential new infrastructure and modifications or additions to these existing in-state facilities is provided in Resource Report No. 1, Appendix L. The Liquefaction Facility, Mainline, and GTP would require the construction of modules that may or may not take place at existing or new manufacturing facilities in the United States.

Resource Report No. 1, Appendix A, contains maps of the Project footprint. Appendices B and E of Resource Report No. 1 depict the footprint, plot plans of the aboveground facilities, and typical layout of aboveground facilities.

Outside the scope of the Project, but in support of or related to the Project, additional facilities or expansion/modification of existing facilities would be needed to be constructed. These other projects may include:

- Modifications/new facilities at the PTU (PTU Expansion project);

- Modifications/new facilities at the PBU (PBU Major Gas Sales [MGS] project); and
- Relocation of the Kenai Spur Highway.

10.1.1 Purpose of Resource Report

As required by 18 Code of Federal Regulations (C.F.R.) § 380.12, the Applicant has prepared this Resource Report in support of a future application under Section 3 of the NGA to construct and operate the Project facilities. The purpose of this Resource Report is to describe the alternatives considered for Project facilities and to support the Least Environmentally Damaging Practicable Alternative (LEDPA) analysis (see Appendix D). The alternatives considered include the following categories:

- Energy alternatives (alternative means to provide the same amount of energy as LNG shipped to foreign markets);
- System alternatives (alternatives to the Project that would make use of other existing, modified, or proposed LNG and/or natural gas facilities to meet the objectives of the Project);
- Site/route alternatives (site locations that were considered as alternative locations for proposed facilities and pipeline routes that were considered as alternatives to the proposed Revision C Mainline centerline);
- Design alternatives (alternative designs that were considered in the design of the facilities that comprise the Project [pipeline, plant power designs, process designs, etc.]); and
- Construction alternatives (alternative means of building or constructing the proposed facilities).

Appendices included in this Resource Report include the following: Appendix A – Databases Evaluated for LNG Facility Siting Alternatives; Appendix B – LNG Facility Siting Alternatives Map; Appendix C – Minor Mainline Route Variations; Appendix D – Least Environmentally Damaging Practicable Alternative Analysis; and E – PTTL Design Crossing Report, Shaviovik River, Kadleroshilik River, and the Sagavanirktok River.

The data for this Resource Report were compiled based on a review of:

- Feedback from FERC and other federal, state, and local agencies on Drafts 1 and 2 of the Environmental Report;
- Engineering design and proposed construction plans;
- United States Geological Service (USGS) topographic maps;
- Recent aerial photography (2008–2014);
- Light detection and ranging (LiDAR) data;

- Environmental data collected through a multi-year field studies program (e.g., wetlands, cultural resources, fisheries, raptor, listed species);
- Geotechnical and geophysical data;
- Stakeholder feedback;
- Review of data from similar projects within the Project footprint (e.g. Denali Pipeline, Alaska Stand Alone Pipeline [ASAP] Project, Alaska Pipeline Project [APP]); and
- Geographic Information System (GIS) data from federal and state agencies, and other projects.

10.1.2 Effect Determination Terminology

The following definitions were used when assessing the duration, significance, and outcome of potential effects related to the Project:

- Duration**:** ***Temporary*** effects are those that may occur only during a specific phase of the Project, such as during construction or installation activities. ***Short-term effects*** could continue up to five years. ***Long-term*** effects are those that would take more than five years to recover. ***Permanent*** effects could occur as a result of any activity that modified a resource to the extent that it would not return to preconstruction conditions during the 30-year life of the Project.
- Significance: ***Minor*** effects are those that may be perceptible but are of very low intensity and may be too small to measure. ***Significant*** effects are those that, in their context, and due to their intensity, have the potential to result in a substantial adverse change in the physical environment.
- Outcome: A ***positive*** effect may cause positive outcomes to the natural or human environment. In turn, an ***adverse*** effect may cause unfavorable or undesirable outcomes to the natural or human environment. ***Direct effects*** are "caused by the action and occur at the same time and place" (40 C.F.R. 1508.8). ***Indirect effects*** are "caused by an action and are later in time or farther removed in distance but are still reasonably foreseeable. Indirect impacts may include growth inducing effects and other effects related to induced changes in the pattern of land use, population density, or growth rate, and related effects on air and water and other natural systems, including ecosystems" (40 C.F.R. 1508.8). Indirect impacts are caused by the Project, but do not occur at the same time or place as the direct impacts.

10.1.3 Agency and Other Consultations

This section describes consultations that have been conducted with agencies and other parties interested in the Project.

10.1.3.1 Federal Agencies

The Applicant's representatives have had discussions with multiple federal agencies regarding Project planning, some of which are contained in this Resource Report. Table 10.1.3-1 includes correspondence and meetings that were held since the pre-filing application was approved (fall of 2014) where alternatives were initially discussed. A list of the required federal permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of public, agency, and stakeholder engagements conducted by the Applicant is provided in Resource Report No. 1, Appendix D.

TABLE 10.1.3-1

Summary of Consultations with Federal Agencies

Contact	Date Contacted	Summary
U.S. Army Corps of Engineers (USACE) U.S. Coast Guard (USCG)	November 21, 2013	Discussion Regarding Pipeline Routing Sensitivities in the Cook Inlet
Bureau of Land Management (BLM) National Park Service (NPS) U.S. Coast Guard (USCG) U.S. Fish and Wildlife Service (USFWS)	February 27, 2014	Pipeline Right-Of-Way Workshop with State and Federal Regulators
National Park Service (NPS) U.S. Environmental Protection Agency (EPA) U.S. Fish and Wildlife Service (USFWS) U.S. Army Corps of Engineers (USACE) Bureau of Land Management (BLM) Federal Energy Regulatory Commission (FERC)	May 12, 2015	Multi-Agency Pipeline Routing Workshop
U.S. Army Corps of Engineers (USACE) U.S. Department of the Interior (USDOI) U.S. Environmental Protection Agency (EPA) U.S. Fish and Wildlife Service (USFWS)	June 24, 2015	Multi-Agency Pipeline Construction Execution Workshop
U.S. Fish and Wildlife Service (USFWS) Federal Energy Regulatory Commission (FERC) National Oceanic and Atmospheric Administration (NOAA)	June 25, 2015	Multi-Agency Waterbody Crossings Workshop
Federal Energy Regulatory Commission (FERC) National Marine Fisheries Service (NMFS) U.S. Army Corps of Engineers (USACE) U.S. Coast Guard (USCG) U.S. Environmental Protection Agency (EPA) U.S. Fish and Wildlife Service (USFWS)	August 12, 2015	Gas Treatment Plant Footprint Review Workshop
Federal Energy Regulatory Commission (FERC) National Marine Fisheries Service (NMFS) U.S. Army Corps of Engineers (USACE) U.S. Fish and Wildlife Service (USFWS)	August 19, 2015	Cook Inlet Routing and Construction Review
Federal Energy Regulatory Commission (FERC) National Marine Fisheries Service (NMFS) U.S. Army Corps of Engineers (USACE) U.S. Coast Guard (USCG) U.S. Fish and Wildlife Service (USFWS)	September 2, 2015	Liquefaction Facility (LNG Plant and Marine Terminal) Footprint Review

TABLE 10.1.3-1

Summary of Consultations with Federal Agencies

Contact	Date Contacted	Summary
Federal Energy Regulatory Commission (FERC) National Marine Fisheries Service (NMFS) U.S. Army Corps of Engineers (USACE) U.S. Coast Guard (USCG) U.S. Environmental Protection Agency (EPA) U.S. Fish and Wildlife Service (USFWS)	September 3, 2015	Dredging Workshop
Pipeline and Hazardous Materials Safety Administration (PHMSA)	November 5, 2015	Tensile Strain Capacity Prediction Technology Development
PHMSA	December 2, 2015	Multi-Layer Coatings, Strain Monitoring and Condition Review.
PHMSA	December 16, 2015	2015 Alaska LNG Project End-of-Year Review
National Park Service (NPS)	February 22, 2016	Mainline Routing Alternatives in the vicinity of Denali National Park and Preserve
PHMSA	February 22, 2016	Strain-Based Design Special Permit Conditions and FERC/NEPA Filing Requirements for Special Permits
Federal Energy Regulatory Commission (FERC)	March 3, 2016	Project Overview
FERC	March 31, 2016	Project Review
FERC	April 14, 2016	Project Review
United States Army Corps of Engineers (USACE) United States Department of the Interior (USDOI) National Park Service (NPS) Alaska Regional Office	April 14, 2016	Pipeline Routing through Denali National Park and Reserve
Alaska Gasline Development Corporation, USDOI, NPS Alaska Regional Office	May 2, 2016	Denali National Park and Preserve Alternative with NPS and ADOT&PF
FERC	July 14, 2016	Uplands Plan and Wetland/Waterbody Procedures
FERC	August 22, 2016	Alaska Agencies Resource Reports Review Workshop in Fairbanks

10.1.3.2 State and Local Agencies

The Applicant's representatives held discussions with multiple State of Alaska and local representatives concerning the Project details contained in this Resource Report. Table 10.1.3-2 includes meetings and correspondence specific to alternatives. A list of the required state permits for the Project is provided in Resource Report No. 1, Appendix C. A summary of public, agency, and stakeholder engagements conducted by the Applicants is provided in Resource Report No. 1, Appendix D.

TABLE 10.1.3-2

Summary of Consultations with State of Alaska and Local Agencies

Contact	Date Contacted	Summary
Alaska Department of Natural Resources (ADNR)	January 9, 2014	Discussion Regarding Gas Treatment Plant Siting
Alaska Department of Fish and Game (ADF&G) Alaska Department of Natural Resources (ADNR) Alaska Railroad Corporation (ARRC) State of Alaska Pipeline Coordinator's Section (SPCS)	February 27, 2014	Pipeline Right-Of-Way Workshop with State and Federal Regulators
Office of Project Management and Permitting (OPMP) State of Alaska Pipeline Coordinator's Section (SPCS)	June 12, 2014	Discussion Regarding Regulatory Limitations and Proposed Routing
Alaska Gasline Development Corporation (AGDC) State of Alaska Pipeline Coordinator's Section (SPCS)	June 12, 2014	Joint Discussion Regarding State Park Lands Permitting
Alaska Department of Transportation and Public Facilities (ADOT&PF)	October 16, 2014	Discussion Regarding the Potential Relocation of the Kenai Spur Highway and Other Project Logistics and Infrastructure Considerations
Alaska Department of Fish and Game (ADF&G) State of Alaska Pipeline Coordinator's Section (SPCS)	October 22, 2014	Discussion Regarding Gas Treatment Plant Water Reservoir Design
Alaska Department of Health and Human Services (ADHHS) Alaska Department of Natural Resources (ADNR) Alaska Department of Transportation and Public Facilities (ADOT&PF) Alaska Department of Fish and Game (ADF&G) State Pipeline Coordinators Office (SPCS) Alaska Department of Environmental Conservation (ADEC) North Slope Borough (NSB) State Historic Preservation Office (SHPO) Denali Borough Kenai Borough Alaska Department of Geology and Geophysical Survey (ADGGS) Department of Revenue (DPOR)	May 12, 2015	Multi-Agency Pipeline Routing Workshop
Alaska Department of Environmental Conservation (ADEC) Alaska Department of Fish and Game (ADF&G) Alaska Department of Natural Resources (ADNR) Alaska Department of Transportation and Public Facilities (ADOT&PF) North Slope Borough (NSB) State Pipeline Coordinators Office (SPCS)	June 24, 2015	Multi-Agency Pipeline Construction Execution Workshop
State of Alaska Pipeline Coordinator's Section (SPCS) Alaska Department of Health and Human Services (ADHHS)	June 25, 2015	Multi-Agency Waterbody Crossings Workshop
Alaska Department of Fish and Game (ADFG) Alaska Department of Natural Resources (ADNR) North Slope Borough (NSB) State Pipeline Coordinators Office (SPCS)	August 12, 2015	Gas Treatment Plant Footprint Review Workshop

TABLE 10.1.3-2

Summary of Consultations with State of Alaska and Local Agencies

Contact	Date Contacted	Summary
Alaska Department of Fish and Game (ADFG) Alaska Department of Natural Resources (ADNR) Kenai Peninsula Borough (KPB) Matanuska-Susitna Borough State Pipeline Coordinators Office (SPCS)	August 19, 2015	Cook Inlet Routing and Construction Review
Alaska Department of Fish and Game (ADFG) Alaska Department of Natural Resources (ADNR) Alaska Department of Transportation and Public Facilities (ADOT&PF) Kenai Peninsula Borough (KPB) State Pipeline Coordinators Office (SPCS)	September 2, 2015	Liquefaction Facility (LNG Plant and Marine Terminal) Footprint Review
Alaska Department of Natural Resources (ADNR) State Pipeline Coordinators Office (SPCS)	September 3, 2015	Dredging Workshop
Alaska Department of Transportation and Public Facilities (ADOT&PF)	October 20, 2015	Review of Integrated Logistics Plan with ADOT&PF Commissioner
Alaska Department of Transportation & Public Facilities (ADOT&PF)	November 24, 2015	Letter to ADOT&PF (John Linnell) – Kenai Spur Highway Re-Route Request for Clarification on URA Applicability
Chikaloon Native Village, Alaska Department of Natural Resources (ADNR)	January 14, 2016	Map Book CD
Chickaloon Village Traditional Council ADNR	January 14, 2016	Map Book CD
Knik Tribal Council ADNR	January 14, 2016	Map Book CD
Native Village of Nuiqsut ADNR	January 14, 2016	Map Book CD
Tyonek Tribal Conservation District, ADNR	January 14, 2016	Map Book CD
Native Village of Tyonek ADNR	January 14, 2016	Map Book CD
Nenana Native Association Toghotthele Corporation ADNR	January 14, 2016	Map Book CD
Kenaitze Indian Tribem ADNR	January 14, 2016	Map Book CD
Alaska House of Representatives – Mike Chenault's office, Alaska State Senate, City of Kenai, City of Soldotna, House of Representatives, Kenai Peninsula Borough (KPB)	March 31, 2016	Mobilization of 2016 Marine Field Work
Alaska Department of Fish and Game (ADFG)	March 31, 2016	Mobilization of 2016 Marine Field Work
State Historic Preservation Office (SHPO)	September 15, 2016	Letter from ADNR (Judith Bittner) – Determinations of National Register Eligibility
Joint House and Senate Resources Committee	September 28, 2016	Alaska LNG Project Legislative Update

10.1.4 Project Purpose and Need

The purpose of the Alaska LNG Project (Project) is to commercialize the vast natural gas resources[2] on Alaska's North Slope, principally by converting the available natural gas supply to LNG for export. There have been numerous unsuccessful efforts to bring this gas to market, including past projects to transport gas by pipeline to the continental United States.[3] As indigenous Lower 48 natural gas supply has increased, an interstate pipeline project from Alaska is currently not economically viable. Foreign demand for natural gas has increased[4], making LNG export the best and only viable option to commercialize these abundant Alaskan resources at this time.

The Project's intention is to deliver natural gas from the PBU and PTU, which is a subset of total North Slope resources.[5] The U.S. Department of Energy (DOE) has conditionally approved an application for the Project to export 20 million metric tons per annum of LNG produced from Alaska for a 30-year period to Free Trade Agreement (FTA) or non-FTA nations.[6] Yet no infrastructure exists to deliver this natural gas to market.

Taking these and other factors into account, including economics, technical requirements and environmental considerations,[7] the Applicant determined the location, throughput, and timing for the Project. A new LNG terminal[8] to export up to 20 MMTPA of LNG,[9] with projected startup in approximately 2024-2025, would include year-round accessible marine facilities near Nikiski, Alaska,[10] as well as liquefaction, pipeline, and gas treatment facilities, connecting North Slope natural gas to foreign LNG markets. This integrated LNG terminal would be the largest LNG project constructed in the United States, with an estimated cost of $40 to $45 billion.

Several important objectives support this substantial investment. The Project would:

- Commercialize natural gas resources on the North Slope during the economic life of the PBU field, and achieve efficiencies through the use of existing common oil and gas infrastructure and economies of scale;

[2] *See* DeGolyer and MacNaughton, "Report on a Study of Alaska Gas Reserves and Resources for Certain Gas Supply Scenarios as of December 31, 2012" at Figure 5 (April 2014).

[3] http://www.arlis.org/docs/vol1/AlaskaGas/Report/Report_CRS_2011_AK_NGP_IssuesCongress.pdf

[4] https://www.mckinseyenergyinsights.com/insights/positive-outlook-for-lng.aspx

[5] DeGolyer and MacNaughton at 11.

[6] DOE/FE Order No. 3554 (granting authorization to export LNG to FTA nations); DOE/FE Order No. 3643 (granting authorization to export LNG to non-FTA nations conditioned on FERC's environmental review process). DOE's non-FTA approval is conditioned on the satisfactory completion of the ongoing FERC-led National Environmental Policy Act (NEPA) review process, in which DOE is a cooperating agency. DOE Order No. 3643, at 9, 42.

[7] *See* Resource Report No. 10 for a full discussion of the alternatives and reasons for selecting the Project.

[8] *See* 18 C.F.R. 153.2(d)(defining "LNG terminal" to include "all natural gas facilities used to … transport, gasify, liquefy, or process natural gas that is … exported to a foreign country from the United States"); *supra* Section 1.1.

[9] DOE/FE Order No. 3554 and Order No. 3643.

[10] Because the Project requires year-round LNG export by waterborne vessels, the purpose and need of the Project is water-dependent.

- Bring cost-competitive LNG from Alaska to foreign markets in a timely manner; and

- Provide at least five interconnection points to allow for in-state gas deliveries, benefiting in-state gas users, and supporting long-term economic development.[11]

In commercializing North Slope natural gas, the Project would offer multiple benefits, all of which are consistent with the public interest. The Project would:

- Stimulate local, state, regional, and national economies through job creation, an enhanced tax base, increased economic activity, and improved U.S. balance of trade, producing "unequivocally positive" economic impacts in Alaska and the United States as a whole;[12]

- Provide a long-term source of revenue to Alaska state and local governments, supporting public services;

- Create up to 15,160 jobs during peak construction and approximately 730 jobs for operation of the Project;

- Create numerous opportunities for Alaska businesses and contractors during construction and operation of the Project;

- Provide infrastructure that may provide opportunity for expansion and incentivize further investment, exploration, and production, leading to more industry activity in the state;

- Support the economic and national security interests of the United States by providing a secure source of energy for its trading partners and contributing to the long-term stability of international energy supply; and

- Produce local, regional, and global environmental benefits by providing, through natural gas and LNG, a cleaner source of energy than many existing alternatives.

10.1.5 Project Siting Requirements

There are several technical criteria any liquefaction facility site should meet to satisfy the Project's purpose:

- The site should be close to an ice-free shipping channel with adequate draft to facilitate shipment of facility modules during construction, and to ensure access by LNGCs during operations;

- The site should also include stable geology and have access to pre-existing road infrastructure and transportation facilities to support construction and operations;

[11] *Id*. (estimating demand for in-state use).

[12] *Id.* at 4-5.

- The proposed industrial use should be compatible with existing surrounding land use(s);
- The site should have sufficient space (approximately 800 acres for construction and operations, including required buffer zones) available for purchase or long-term lease;
- The site should have favorable terrain to accommodate construction of the facilities;
- The site should avoid wetlands, cultural resources, protected conservation land, protected fish and wildlife habitat, and communities, to the extent practicable; and
- The site should be capable of being permitted and meeting regulatory requirements for construction and operation.

Agency and stakeholder concerns that were known at the time of siting efforts for the Liquefaction Facility and Interdependent Project Facilities were also taken into consideration.

Additional Interdependent Project Facilities required to support the overall Project have the following siting requirements:

- A GTP site to treat natural gas extracted from the PBU and PTU North Slope reservoirs and deliver it to the Mainline would be needed. The site should be located within an existing industrial complex to minimize the infrastructure development required. The site should have access to existing infrastructure (roads, power, dock), resources (granular material, fresh water), and be in proximity to a dock on the Beaufort Sea coast for the delivery of modules during construction. Additionally, the site should be in reasonable proximity to the existing PBU gas production, conditioning, and reinjection facilities.
- A Mainline and associated facilities (e.g., compressor stations, heater stations, meter stations, MLBVs, launchers/receivers) necessary to support transportation of natural gas from Alaska's North Slope to the LNG terminal that would avoid or reduce as appropriate, to the extent practicable, impacts to known cultural resource sites, wilderness and/or protected conservation lands, wetlands, protected fish and wildlife species and/or habitat, visual aesthetics, and communities would be needed. Technical criteria include shortest pipeline distance possible, favorable terrain and geotechnical conditions, sufficient right-of-way (ROW) space, pipeline design, execution planning, operability, and meeting codes and regulations.
- Transmission lines and associated facilities necessary to connect the GTP to the PBU and PTU gas production facilities would be needed. These pipelines would avoid or reduce, as appropriate and to the extent practicable, impacts to known cultural resource sites, wilderness and/or protected conservation lands, wetlands, protected fish and wildlife species and/or habitat, visual aesthetics, and communities. Technical criteria include shortest pipeline distance possible, favorable terrain and geotechnical conditions, sufficient ROW space, pipeline design, execution planning, operability, and meeting codes and regulations.

Project alternatives were evaluated (providing they satisfied the prior technical criteria) by comparing relative level of adverse environmental effects as well as technical and logistical feasibility and cost.

10.1.6 Avoiding and Reducing Environmental and Social Impacts

National Environmental Policy Act (NEPA), FERC regulations, and the Clean Water Act (CWA) Section 404(b)(1) Guidelines (Guidelines) all require an analysis of alternatives. This includes a discussion of the measures to avoid, reduce, and restore/enhance/preserve that are employed to minimize and offset impacts to the human environment and/or the aquatic ecosystem.

NEPA specifically requires a discussion of a reasonable range of alternatives associated with any project involving a major federal action such as a federal license or permit. These alternatives must include the "No Action" alternative, as well as the Applicant's proposed alternative.

FERC regulations for pre-filing under the NGA require that the Environmental Reports (and specifically Resource Report No. 10) include a discussion of alternatives. Resource Report No. 10 is required for all applications to FERC and "must describe alternatives which were considered during the identification of the Project and compare the environmental impacts of such alternatives to those of the proposal" (2002 FERC Guidance Manual).

The CWA requires an analysis of all practicable alternatives to identify the LEDPA. The Guidelines state that "Except as provided under section 404(b)(2), no discharge of dredged or fill material shall be permitted if there is a practicable alternative to the proposed discharge which would have less adverse impact on the aquatic ecosystem, so long as the alternative does not have other significant adverse environmental consequences" (40 C.F.R. 230.10). If the Project is located in a special aquatic site (i.e., wetlands, mudflats, vegetated shallows, riffle and pool complexes, coral reefs or sanctuaries and refuges), then the Guidelines require that a "water dependency" test be applied as well. A project is water dependent only if it requires access or proximity to or siting within a special aquatic site to fulfill its basic purpose. Few projects actually do require siting in a special aquatic site; therefore, the Guidelines state that practicable alternatives are assumed to exist that would have less environmental impact and a full analysis of all practicable alternatives is required.

An alternatives analysis for the Project was performed in compliance with each of these requirements, as outlined in the sections that follow (see Appendix D). LEDPA considerations were incorporated into the alternatives analysis. This included assessing whether potential alternatives would result in less identifiable or discernible impacts on the aquatic ecosystem. Those alternatives that would not result in less identifiable or discernible impacts were eliminated from further analysis in accordance with 40 C.F.R. Section 230.10(a) of the Guidelines (which only prohibits discharges when a practicable alternative exists that would have less adverse impact on the aquatic ecosystem).

Part of making a LEDPA determination is assessing the level of analysis required for determining whether an alternative is practicable varies depending on the type of project. An alternative is considered to be "practicable" if it is available and capable of being done after taking into consideration cost, existing technology, and logistics in light of overall project purposes. The determination of what constitutes an unreasonable expense takes into consideration whether the projected cost is substantially greater than the costs normally associated with the particular type of project. If an alternative is so expensive that it is cost-prohibitive in light of the overall project purpose and need, the alternative is not deemed practicable and is eliminated from further analysis. Likewise, if an alternative is not capable of being constructed using existing technology and/or if logistical issues (like safety and security) resulted in the alternative being considered not practicable, the alternative is eliminated from further analysis.

Even where a practicable alternative exists that would have less adverse impact on the aquatic ecosystem, the Guidelines consider rejection of the alternative if it would have "other significant adverse environmental consequences." It is not considered appropriate to select an alternative where minor impacts on the aquatic environment are avoided at the cost of substantial impacts to other natural environmental values. If an alternative is deemed to have other significant adverse environmental consequences, the alternative is not deemed practicable and is eliminated from further analysis.

10.2 NO-ACTION ALTERNATIVE

NEPA regulations require consideration of the No-Action Alternative (40 C.F.R. § 1502.14(d)), which may be used as a benchmark for comparison of the environmental effects of the proposed action and a reasonable range of alternatives. Under the No-Action Alternative, the Project would not be undertaken, and the associated environmental impacts from construction and operation of the Project would not occur. However, other environmental impacts would likely result from generation and use of energy sources other than natural gas (See Section 10.2.1) and as a result of some future project to commercialize Alaska North Slope gas.

The No-Action Alternative would not accomplish the Project purpose and objectives as set forth in Section 10.1.3. The No-Action Alternative would fail to: (1) commercialize natural gas during the economic life of the PBU field to achieve efficiencies through the use of existing common oil and gas infrastructure and economies of scale; (2) provide cost-competitive LNG to foreign markets; or (3) allow for in-state deliveries of natural gas by providing at least five interconnection points. Furthermore, the No-Action Alternative would forego important benefits associated with the Project, including to: (1) stimulate local, regional, state, and national economies through job creation and economic activity; (2) provide a long-term source of revenues to the State of Alaska and local communities; (3) create infrastructure to support future development of gas supplies in Alaska; (4) reduce reliance on fossil fuels that have greater environment impact; and (5) increase national security by reducing the need for foreign countries to import LNG from other countries with less stable governments.

10.2.1 Alternative Energy Resources

The No-Action Alternative could force potential natural gas customers to seek other sources of energy. It is uncertain whether the No-Action Alternative would result in international energy conservation or substitution of energy sources with greater environmental impacts than natural gas. As such, the alternative energy sources evaluated relative to the Project include the following:

- Biomass;
- Coal;
- Geothermal;
- Hydrokinetic (wave and tidal);
- Hydropower;
- Nuclear;
- Oil;
- Solar; and
- Wind energy.

Additional information about the alternative energy resources that were evaluated can be found in Table 10.2-1.

Many industrialized countries are emphasizing the use of renewable energy resources such as wind or solar power as a means to reduce greenhouse gas (GHG) emissions and other pollutants. However, contributions from renewable energy represent a small share of the energy mix, and many renewable sources are intermittent in their availability over the course of a day or season and in rural portions of undeveloped nations.

Consequently, other energy sources are essential to account for the balance in total energy needs, and thus natural gas has a growing role in the global energy mix. Natural gas has many attributes that make its use attractive, including that it is available in abundant quantities, it is a dependable base-load fuel source, and it is economically viable. As described in Table 10.2-1, natural gas use also has clear environmental advantages when compared to other fossil fuel alternatives.

LNG exported to foreign markets could serve as a complement to renewable energy sources that are not as economically achievable or cost-effective for certain nations or locations. Similarly, any Alaska in-state gas deliveries could displace consumption of more emission-intensive fuels such as fuel oil, coal, or wood (e.g., Fairbanks), and complement any local use of renewables.

In all cases, none of the alternative energy sources meet the Project's stated purpose and need.

TABLE 10.2-1

Alternative Energy Resources to Natural Gas

Alternative Energy Resource	**Preferred Alternative Over Natural Gas**	**Description and Limitations**
Biomass	No	Biomass energy can be used to generate electricity and heat by burning wood wastes, combusting pulping liquor at pulp mills, and tapping methane gas at landfills and wastewater treatment facilities. However, biomass combustion has availability, environmental, and reliability issues that have limited its role to a small percentage of the overall energy supply in foreign markets.[a]
Coal	No	Although coal is a readily available energy alternative in many countries, it does not burn as cleanly as natural gas, which emits half as much CO_2 as coal, and less than a third as much nitrogen oxides. The burning of coal results in adverse effects on air and water quality, including acid rain, unless costly air pollution controls are installed at coal-burning power plants. Increased reliance on coal would lead to adverse environmental effects related to additional coal mining and the transportation of coal to power plants. Attempts to develop commercial-scale, “clean-coal” power plants that use carbon sequestration technologies are still largely in the early stages of development.
Geothermal	No	To date, geothermal resources do not provide a measurable portion of global energy supply. Theoretically, geothermal electric generation could provide significant renewable base load quantities in the long term.[b] However, it is not currently used or planned for use on a commercial scale except in relatively few countries like Iceland.
Hydrokinetic (wave and tidal)	No	Hydrokinetic energy is the energy held by a body of water through the water’s motion. Hydrokinetic power involves harnessing energy from waves, tides, or currents. Specific devices have been designed to capture energy from water in motion. One of the main benefits of hydrokinetic energy is that it can be harnessed continuously, without direct dependence on sunlight or wind. However, the technology is geographically specific and not yet sufficiently developed to be considered a viable alternative for the foreign markets targeted by the Project.[c]
Hydropower	No	The development of new hydropower energy sources is widespread in some foreign locations. Potential adverse environmental effects associated with hydropower energy are now also recognized, such as impairment to fish migration and flooding of inhabited land.[d]
Nuclear	No	Nuclear energy limits the air emissions of greenhouse gases (GHGs) and other criteria air pollutants. However, nuclear energy generation can result in long-term environmental effects associated with disposal of radioactive waste products. In addition, nuclear energy has traditionally faced negative public perception concerning the inherent safety risks. Worldwide public scrutiny of nuclear facilities following the 2011 Fukushima Daiichi nuclear disaster in Japan has resulted in a significant reevaluation and shutdown of select nuclear power plants. Current obstacles to new nuclear facilities include: 1. Challenging regulatory hurdles, such as regulatory authorizations; 2. Lack of financing; and 3. Shortage of necessary associated infrastructure.
Oil	No	The burning of natural gas results in fewer air quality emissions than any liquid hydrocarbon.[a]
Solar	No	Solar energy comprises a very small percentage of the global energy supply.[a] Therefore, solar energy is not viewed in the near term as providing the quantity of energy comparable to LNG exports from the Project. Continued technological advances and decreases in the installation costs of solar electrical systems are required before this source is a viable energy alternative.[f]

TABLE 10.2-1

Alternative Energy Resources to Natural Gas

Alternative Energy Resource	Preferred Alternative Over Natural Gas	Description and Limitations
Wind	No	Although growing as a renewable energy source, wind energy comprises a very small percentage of the overall energy supply in foreign markets.[a] Thus, wind energy is not capable of providing a quantity of energy comparable to LNG exports from the Project. With continued technological advances, wind energy may become a viable energy alternative for suitable geographic regions.
Energy Conservation	No	Energy savings from energy conservation practices could alleviate some of the growing demand for energy. However, energy conservation requires widespread political will, industry research, and industry development before it will become a viable alternative for significantly lowering the demand for a reliable energy source.[g]

Source:
[a] EIA. 2011. International Energy Outlook 2011. http://www.eia.gov/forecasts/ieo/pdf/0484(2011).pdf. U.S. Department of Energy.
[b] International Energy Agency. 2011. Technology Roadmap – Geothermal Heat and Power. https://www.iea.org/publications/freepublications/publication/Geothermal_Roadmap.pdf.
[c] International Energy Agency. 2012. World Energy Outlook – 2012. http://www.worldenergyoutlook.org/publications/weo-2012/.
[d] EPA. 2013. Hydroelectricity-Environmental Impacts. http://www.epa.gov/cleanenergy/energy-and-you/affect/hydro.html.
[e] International Energy Agency. 2015. Technology Roadmap – Nuclear Energy. http://www.iea.org/publications/freepublications/publication/TechnologyRoadmapNuclearEnergy.pdf.
[f] International Energy Agency. 2014. Technology Roadmap – Solar Photovoltaic Energy. https://www.iea.org/publications/freepublications/publication/TechnologyRoadmapSolarPhotovoltaicEnergy_2014edition.pdf.
[g] EPA and DOE. 2010. Coordination of Energy Efficiency and Demand Response. http://www.epa.gov/cleanenergy/documents/suca/ee_and_dr.pdf.

10.3 LIQUEFACTION FACILITY ALTERNATIVES

10.3.1 Liquefaction Facility System Alternatives

System alternatives are alternatives to the Project that would make use of other existing, modified, or proposed LNG and/or natural gas facilities to meet the objectives of the Project. System alternatives may make it unnecessary to construct all or part of the Project, although modifications or additions to the system alternative may be required to increase capacity or provide receipt and delivery capability consistent with that of the Project. Such modifications or additions may result in environmental impacts less than, comparable to, or greater than those associated with Project construction and operation. System alternatives are analyzed to determine whether potential environmental effects associated with Project construction and operation could be avoided or minimized while still allowing the stated purpose and need of the Project to be met. To be a viable system alternative to the Project, any potential alternative should meet at least the following requirements:

- Satisfy Project purpose and needs;
- Be technically viable;
- Be economically feasible;
- Provide a substantial environmental advantage over the proposed Project; and
- Be able to secure all applicable authorizations to meet the Project schedule.

System alternatives were evaluated for a new facility constructed on the eastern shore of Cook Inlet in the Nikiski area of the Kenai Peninsula (Applicants' proposed alternative). To evaluate these potential system alternatives, the Project summaries provided by FERC (2017) were reviewed for the following:

- Existing LNG export terminals;
- Authorized, but not yet constructed, LNG export terminals; and
- Proposed or planned LNG export terminals.

The potential export of natural gas solely via pipeline was also evaluated but eliminated as not economically viable.

As discussed in the following section, none of the existing, proposed, or authorized LNG export terminals would be reasonable alternatives because of the extensive facilities required to move the North Slope natural gas into any of these planned, proposed, or existing LNG plants. The additional costs alone would make the Project uneconomical in the foreign LNG marketplace, preventing the Project from meeting its intended purpose and need. As discussed in the following sections, the additional impacts that would result from the use of any of these facilities (i.e., two to seven times the pipeline length) would result in a much greater impact than would the proposed Project.

10.3.1.1 Existing LNG Export Terminals and Marine Facilities

10.3.1.1.1 Kenai LNG

ConocoPhillips Alaska's Kenai LNG Plant located in Nikiski (see Figure 10.3.1-1 and Resource Report No. 1, Appendix A) began operating in 1969, and for more than 40 years was the only LNG export plant of domestic production in the United States (ConocoPhillips Alaska, 2013). In 2013, the plant's export license expired. Due to a change in market conditions, including additional gas supplies in the Cook Inlet Basin, ConocoPhillips Alaska was granted a new license in 2014 that allows export of the equivalent of 40 billion cubic feet of LNG over a two-year period (ConocoPhillips Alaska, 2014). The existing Kenai LNG Plant is currently operating, and ConocoPhillips has no near-term plans to terminate its use. Current Kenai LNG FTA and non-FTA authorizations expire in 2018.

The existing Kenai LNG Plant does not accommodate the Project purpose and need. Its production capacity (approximately 1.3 MMTPA) is one-fifteenth of the design capacity of the Project (up to 20 MMTPA). The current Kenai LNG Plant site does not contain sufficient acreage for expansion. This is because the site is in the proximity of nearby industrial facilities and the existing, operating Tesoro and non-operating Agrium facilities, and expansion to accommodate the required footprint is not feasible without adversely affecting these existing facilities. Therefore, it is not practicable to alter the existing site to accommodate the Project's proposed purpose and need.

Shared use of existing Kenai LNG associated facilities was considered for the Project. However, the existing Kenai plant is still in operation and will need continued, uninterrupted use of these facilities in the foreseeable future. The Kenai LNG Plant associated facilities were sized for the Kenai Plant's specific capacity and are not sufficient to meet Project plant requirements.

Offsite connection of the proposed Liquefaction Facility with the Kenai Plant is physically possible. Such an offsite connection would allow for use of the some of the existing associated facilities (e.g., berth).

However, the routing of the connecting cryogenic piping would trigger buffer zone requirements that could not be readily accommodated and that would require rerouting a longer stretch of the Kenai Spur Highway than is currently proposed for the Project. In addition, the existing marine facilities would need to be completely rebuilt to accommodate the purpose and needs of the Project. Locating the new Marine Terminal in between the existing Tesoro and Agrium marine berths would also likely result in marine operational constraints (through terminal design constraints and LNGC restrictions to avoid conflicts with neighboring terminals). Further, to commercialize North Slope gas, new gas treatment and pipeline infrastructure from the North Slope to Southcentral Alaska would still be required that could have environmental effects equivalent to that required for the proposed Project. Because of these factors, expansion of the existing Kenai LNG Plant does not present a viable alternative to the proposed Project, and will not be analyzed in further detail.

The Applicant are still evaluating potential use of nearby marine facilities to support construction activities and minimize dredging and construction impacts without impeding existing use of the facilities.

10.3.1.1.2 Sabine Pass LNG

In February 2016, Sabine Pass LNG (FERC Docket Nos. CP11-72-000 and CP14-2-000) exported the first LNG cargo from the Lower 48 states. The facility is currently sized at 10.9 MMTPA and is located in Cameron Parish, Louisiana.

For the same reasons that are discussed in detail in Section 10.3.1.2, use of an export terminal from the Lower 48 states would not meet the Project's stated purpose and need (to export natural gas in the form of LNG from supplies in the North Slope of Alaska). Not only would construction and operation costs be higher, but the cost of shipping to most markets would also increase due to increased distance. In addition, the Sabine Pass capacity is mostly, if not fully, subscribed[13]. As such, use of the Sabine Pass facility was determined to not be a viable system alternative and was not further evaluated.

10.3.1.2 Proposed, Planned, or Approved LNG Export Terminals

A potential system alternative to the proposed Project is use of an existing or approved North American export or import terminal. There are currently several existing and approved export and import facilities in the United States and Canada, including the facilities listed in the following sections (FERC, 2017; volumes are listed as provided by FERC, 2017) (see Figures 10.3.1-1 through 10.3.1-3). Existing import terminals would need to be licensed to allow export and/or be bidirectional. This action would require a full NEPA analysis and require additional facilities to liquefy the natural gas for export.

[13] Sabine Pass Liquefaction has indicated that all liquefaction capacity has been sold at the liquefaction project. For additional information, please refer to the Sabine Pass Liquefaction Section 3 Application (CP11-72).

VICINITY MAP

LEGEND

- Existing and Authorized to Re-Export Delivered LNG
- Existing and Authorized to Import LNG
- Existing LNG Export Facility

Non-US facilities are listed in Resource Report No. 10

0 175 350 700 Miles

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DATE:	2017-03-23	SHEET:	1 of 1

THE LOCATION OF EXISTING LNG FACILITIES

FIGURE 10.3.1-1

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_3_1-1 - The Location of Existing LNG Facilities.mxd

VICINITY MAP

LEGEND

Existing LNG Import Facility

Approved LNG Facility Type

LNG Export Terminal

LNG Import Terminal

Construction Status

Not Under Construction

Under Construction

0 175 350 700 Miles

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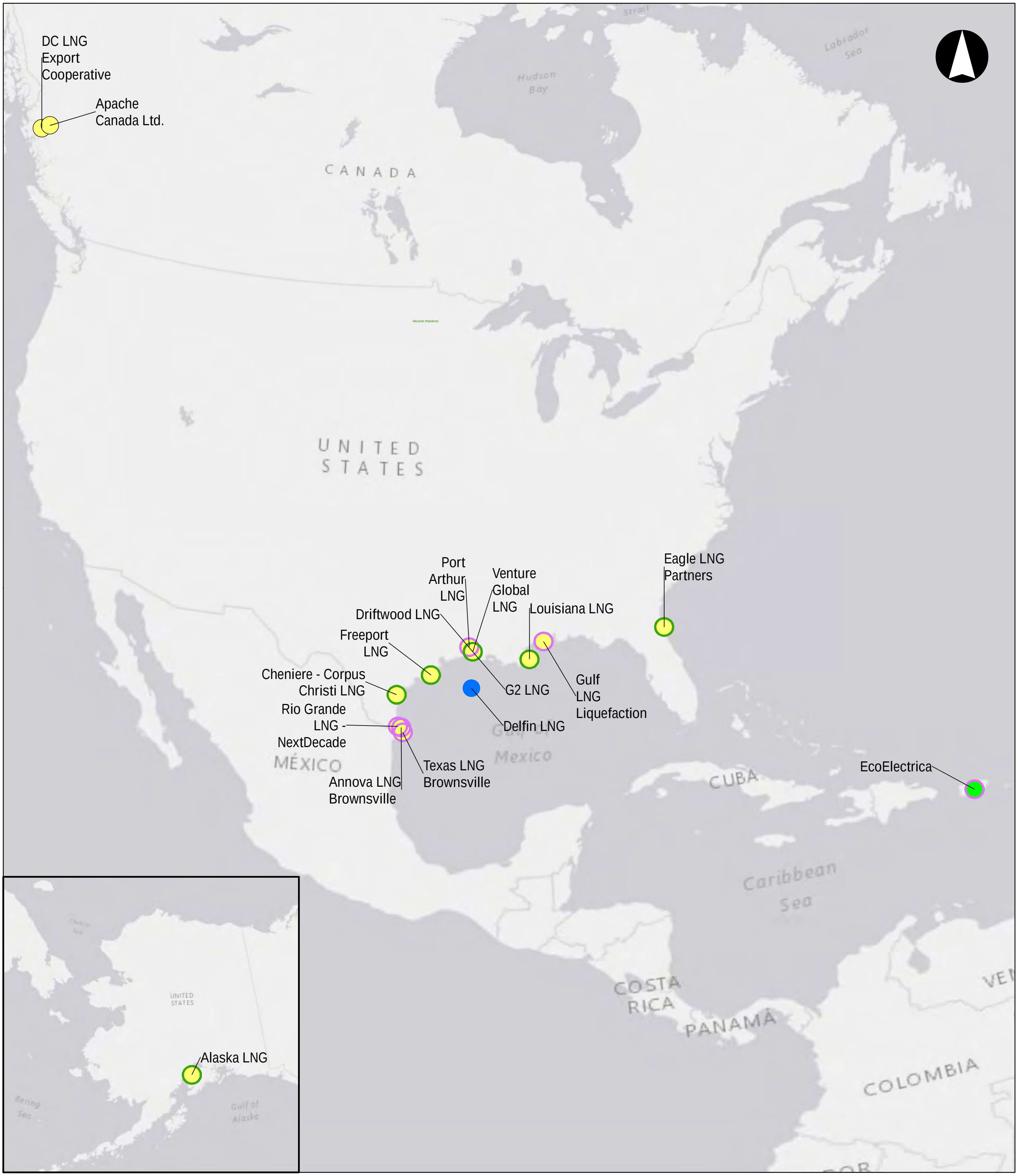
THE LOCATION OF APPROVED LNG FACILITIES

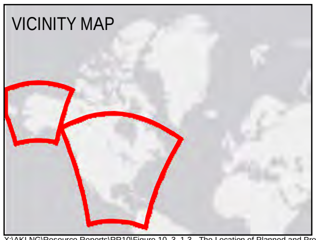
FIGURE 10.3.1-2

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_3_1-2 - The Location of Approved LNG Facilities.mxd



VICINITY MAP



LEGEND

- LNG Export Terminal
- LNG Import Terminal
- LNG Export Facility Proposed to U.S.-MARAD/COAST GUARD

FERC Status

- Application Pending
- Project in Pre-Filing

0 175 350 700 Miles

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THE LOCATION OF PLANNED AND PROPOSED LNG EXPORT FACILITIES

FIGURE 10.3.1-3

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_3_1-3 - The Location of Planned and Proposed LNG Export Facilities.mxd

10.3.1.2.1 Existing with Expansions Planned or Under Construction

- Cameron LNG (Hackberry, Louisiana) – The existing terminal, sized at 14.1 MMTPA, is authorized to export 27.5 MMTPA (FERC Docket No. CP13-25-000; FERC Docket No. CP15-560).

- Cheniere – Corpus Christi LNG (Corpus Christi, Texas) – The approved terminal, sized at 3.1 MMTPA, is authorized to export 16.7 MMTPA FERC Docket No. (CP12-507-000). An additional 11.0 MMPTA is proposed (FERC Docket No. CP15-26).

- Dominion Cove Point LNG Terminal (Chesapeake Bay in Lusby, Maryland) – The existing terminal is sized at 14.1 MMTPA. Approval was received to export 6.4 MMTPA (FERC Docket No. CP13-113-000).

- Freeport LNG Development, LP (Freeport LNG, Brazoria County, Texas) – The existing terminal, sized at 11.8 MMTPA, is authorized to export 16.8 MMTPA (FERC Docket No. CP15-518). An additional 5.6 MMTPA has been proposed (FERC Docket No. PF15-25).

- Sabine Pass LNG, LP (Sabine Pass LNG) – The existing import terminal, sized at 31.4 MMTPA, is approved for an additional 22 MMTPA for export (FERC Docket Nos. CP11-72-000, CP14-12-000, CP13-552-000; Cameron Parish, Louisiana).

- Southern LNG Company (Elba Island) Terminal (Savannah, Georgia) – Existing LNG import terminal with a send-out capacity of 12.5 MMTPA. The facility has been approved (FERC Docket No. CP14-103) to export 2.7 MMTPA.

10.3.1.2.2 Approved, Not Under Construction

- Bear Head LNG – Sized at 3.9 MMTPA (Port Hawkesbury, Nova Scotia);

- Golden Pass Products LLC (Golden Pass LNG, Sabine Pass, Texas) – Existing LNG import terminal, with a send out capacity of 15.7 MMTPA, is approved to export 16.5 MMTPA (FERC Docket No. CP14-517).

- LNG Canada – Sized at 25.3 MMTPA (Kitimat, B.C.);

- Magnolia LNG – Proposed at 8.5 MMTPA (FERC Docket No. CP14-347-000; Lake Charles, Louisiana);

- Pacific Northwest LNG – Proposed at 21.5 MMTPA (Prince Rupert Island, B.C.);

- Trunkline LNG Company, LLC (Southern Union - Lake Charles LNG, Calcasieu Parish, Louisiana) – Existing LNG import terminal with a 16.5 MMTPA capacity, authorized for 17.2 MMTPA for export (FERC Docket No. CP14-120); and

- Woodfibre LNG – Proposed at 2.3 MMTPA (Squamish, B.C.).

10.3.1.2.3 Proposed or Planned Terminals

There are currently several proposed or planned export facilities in the United States and Canada including the following (FERC, 2017; volumes are listed as provided by FERC):

- Annova LNG – Proposed at 7.1 MMTPA (FERC Docket No. CP16-480; Brownsville, Texas);
- Apache Canada – Proposed at 10.0 MMTPA (Kitimat, B.C.);
- BC LNG Export – Proposed at 1.8 MMTPA (Kitimat, B.C.);
- Delfin LNG – Proposed at 14.1 MMTPA (Gulf of Mexico – proposed to U.S. Maritime Administration/U.S. Coast Guard [USCG]);
- Driftwood LNG – Proposed at 31.4 MMTPA (FERC Docket No. PF16-6; Calcasieu Parish, Louisiana);
- Eagle LNG Partners – Proposed at 0.6 MMTPA (FERC Docket No. PF15-7; Jacksonville, Florida);
- G2 LNG – Proposed at 14.4 MMTPA (FERC Docket No. PF16-2; Cameron Parish, Louisiana);
- Gulf LNG Energy, LLC (Gulf LNG, Jackson County, Mississippi) – Existing terminal with a send out capacity of 11.8 MMTPA (FERC Docket No. CP15-521; proposed for export is 11.8 MMTPA).
- Port Arthur LNG – Proposed at 14.6 MMTPA (FERC Docket No. CP17-20; Port Arthur, Texas);
- Rio Grande LNG – Proposed at 28.2 MMTPA (FERC Docket No. CP16-454; Brownsville, Texas);
- Texas LNG – Proposed at 4.3 MMTPA (FERC Docket No. CP16-116; Brownsville, Texas);
- Venture Global LNG – Proposed at 11.1 MMTPA (FERC Docket No. CP15-550; Cameron Parish, Louisiana);
- Venture Global LNG – Proposed at 22.0 MMTPA (FERC Docket No. PF15-27; Plaquemines Parish, Louisiana).

None of these approved, planned, or proposed facilities meet the Project stated purpose and need (to export natural gas in the form of LNG from supplies in the North Slope of Alaska). Although all would obviate the need of the Liquefaction Facility in Southcentral Alaska and avoid the impacts associated with building and operating the Liquefaction Facility, that reduction in impact would be more than offset by the construction and operation of a much longer pipeline system to reach from the Alaska North Slope to one of these facilities. In the United States, the closest LNG export terminal project, Dominion Cove, is located in Cove Point, Maryland, approximately 3,350 miles from the proposed GTP facility (minimum straight-line distance), which is almost four times the length of the Applicants' proposed alternative. The additional length of pipeline would increase the operating costs of the pipeline (and Project) both through additional compressor stations and additional fuel use. Both of these would also result in greater environmental impacts. Similarly, the LNG export projects proposed in Canada in British Columbia, would be located approximately 1,250 miles from the proposed GTP facility, which would require a pipeline almost approximately 50 percent longer than the Mainline.

Selection of a system alternative to use existing or planned LNG export terminals would not be economically feasible. Not only would construction and operating costs be higher, but the cost of shipping to most markets would also increase due to increased distance between the terminal and the market. Therefore, the Alaska LNG Project (Project) is the most environmentally preferable and practical alternative from the pool of existing/proposed system alternatives, because it is the only considered site that fully satisfies the Project's purpose and need, while minimizing environmental impacts. As such, use of a different proposed or planned export terminal was determined to not be a viable system alternative and was not further evaluated because these proposed projects are located along the Canadian or U.S. (Pacific and Gulf of Mexico) coasts and cannot meet the stated purpose and need of the Project without significant modifications to the proposed or planned facilities and the distance from the gas supply.

10.3.1.3 Export of Natural Gas via Pipeline

The primary purpose of the Project is to commercialize North Slope gas by exporting LNG to foreign markets. International transport of LNG by vessel has the advantage of greater flexibility over natural gas transport via pipeline, because it is not bound to a rigid piping system with fixed starting and end points. As a consequence, LNG allows for dispersed and flexible delivery points. Economically, LNG is more competitive for long-distance transport of natural gas, because overall costs (construction, maintenance, and operation) are less affected by distance (Cornot-Gandolphe et al., 2003; Messner and Babies, 2012). Direct export of North Slope natural gas to overseas foreign markets by pipeline would not be technically or economically feasible. The direct transport of Alaska North Slope natural gas to locations outside Alaska, though technically feasible, would not be economically feasible because of the long distances to these markets (more than 2,000 miles to the nearest Asian markets). Accordingly, the direct transport of natural gas transport by pipeline to foreign markets by pipeline rather than as LNG by vessel is not a practicable, economic, or reasonable alternative.

10.3.1.4 Generation of Power on the North Slope

The principal purpose of the Project is to move the vast supplies of natural gas in Prudhoe Bay and Point Thomson to foreign markets as well as provide for the residents of Alaska with a source of natural gas. Generating power on the North Slope would not meet the Project purpose to move natural gas to foreign markets.

As described in Section 10.1.3, to serve the residents of the State of Alaska, one of the main objectives of the Project is to provide at least five interconnection points to allow for in-state gas deliveries, benefiting in-state gas users, and supporting long-term economic development. An alternative to in-state delivery via pipeline would be to use North Slope natural gas to generate electric power on the North Slope and then construct transmission line infrastructure to supply end users. This alternative would require a much smaller quantity of natural gas than would the proposed Project, approximately 1–2 trillion cubic feet over the 30-year life of the Project. The gas would still need to be treated through a GTP to provide processed natural gas to fuel a power plant on the North Slope. Direct Current (DC) or traditional Alternating Current (AC) power transmission lines would need to be built for the approximate 807 miles along the route of the proposed pipeline. ROWs for powerlines are typically much larger than for pipeline ROWs, ranging from 200 to 500 or more feet in width, depending on the nature of the powerline (DC versus AC), the tower height and design, and terrain. DC or AC powerlines would require a large footprint to step down power to provide the equivalent amount of energy to local communities along the transmission line. In addition, construction of a power plant on the North Slope would require a relatively large facility footprint, a large water supply (marine or freshwater) to provide cooling water, and result in increased air emissions on the North Slope beyond GTP emissions. Most importantly, generation of power on the North Slope instead of natural gas transport by pipeline would not meet the Project's primary purpose to commercialize North Slope gas by exporting LNG to foreign markets. As such, generation of power on the North Slope was determined not to be a viable alternative.

10.3.2 Liquefaction Facility Site Alternatives

10.3.2.1 Introduction

The focus of the siting efforts for the Liquefaction Facility was to find a suitable location for an approximately 800- to 1,200-acre site with access for LNGCs that was supported locally with appropriate terrain, geology, zoning, and supporting infrastructure. All studied sites were sized to comply with 49 C.F.R. 193 with respect to estimated vapor dispersion zones and thermal radiation (approximately 800 acres).

Over the course of several years, the Applicant conducted an iterative process to identify, screen, assess, and select the proposed alternative for the Liquefaction Facility. This process was conducted using primarily information from prior projects, existing information from agencies, as well as publicly available and Project-derived information in a series of desktop studies with limited site investigations and surveys conducted.

Early in the process, the option to site the facility on the North Slope was eliminated due to the impracticability of building and operating a Liquefaction Facility on the North Slope for the following reasons:

- The annual ice-free window allowing shipping from North Slope is only about two to three months, so year-round LNG shipping would require specialized ice-breaking LNGCs and loading facilities capable of withstanding Arctic ice conditions, including shorefast ice. Even if the ice-free season were to increase in the future, the Project design would have to address the existing ice regime.

- The Beaufort Sea is very shallow near shore and a loading facility would need to be either located tens of miles offshore, or dredging would be required to place the facility at the shore with a dredged channel access. In the Prudhoe Bay area, it is approximately 3 miles to 15-foot depth feet and 20 miles to 60-foot depth. This construction would require extensive granular material lay in the nearshore environment, which would have associated impacts to marine mammals and fish. There would also be concerns related to impacts on subsistence whaling. Additionally, pumping LNG to carriers would increase energy input with a resultant increase in heat transfer and production of boil-off gas (BOG) volumes, greatly increasing BOG recovery requirements and associated offshore infrastructure requirements.

- If a longer trestle or the Liquefaction Facility is not sited offshore, extensive dredging would be required (almost 3 miles to the 15-foot depth contour), along with annual dredging because of the dynamic nature of the sediment loading along the shallow Beaufort Sea coastline.
- Construction of the Liquefaction Facility, together with the GTP construction and the limited number of modules that could be offloaded in any given year, would require many years of sealifts for the modules to be delivered to both sites (likely eight or more years), or the construction of a second dock near West Dock to allow both facilities to offload modules in the same season. Additional haul roads would be required from the new dock to facilitate transportation to both sites simultaneously. In addition to these impracticalities, the costs would be significantly higher because of the unique designs (requiring testing prior to operations), longer construction time period, as well as the higher costs of building facilities on the North Slope (slower production rates).

The impracticalities as well as the significantly higher costs eliminated the North Slope from further consideration.

Siting a Liquefaction Facility on a western shoreline of Alaska would face similar challenges to siting a facility in the Prudhoe Bay area. It is not practical to site a Liquefaction Facility along the west coast of Alaska because:

- Existing ports on the northwest portion of the state that are closest to the gas supply would have similar ice cover restrictions as in Prudhoe Bay and would require ice-breaking LNGCs and an ice-reinforced marine terminal.
- Unlike siting a facility in Southcentral Alaska, there are no existing industrial support facilities or existing infrastructure (roads and railroads) that facilitate construction and operations in that region of Alaska.
- A pipeline from the North Slope production units to a western Alaskan port on the Chukchi Sea or Bering Sea coasts would traverse numerous federal and state lands in various conservation uses (National Parks, National Wildlife Refuges [NWRs], Areas of Critical Environmental Concern [ACECs]) that would be greatly impacted by opening up a linear corridor in designated conservation lands.
- Routing a pipeline to the facility from the North Slope production units would also traverse areas that have no existing infrastructure (roads, railroad, material source sites, airports/airstrips, etc.) to support construction of the pipeline. This would require building the infrastructure that would open up undeveloped areas to the greater public, which would result in biological and community impacts.
- Because of the remoteness of the area, there would be considerable schedule impacts to build the infrastructure and then build the facilities (as well as the lengthened permitting timeframes when traversing an undeveloped area of Alaska).

- A pipeline to the western portions of Alaska would also not provide the benefit of supplying gas to more heavily populated regions of the state without a separate pipeline.

10.3.2.2 Siting Methodology

The siting methodology consisted of an iterative review of potential sites with a multidisciplinary team during two major studies—a screening study to identify and assess at a high level potential sites in Southcentral Alaska, and a feasibility study to assess the ability to cost-effectively design, permit, build, and operate a Liquefaction Facility at a site. There were several rounds of iterative analysis conducted (one round in the screening study and several in the feasibility study).

A list of the specific databases used for the analysis is provided in Appendix A.

10.3.2.2.1 Siting Criteria

During the screening study, the initial list of sites (see the following for the method on site identification) were assessed to determine if there were any potentially significant issues identified related to:

- Engineering/geology: Sites farthest from known volcanic activity using USGS data, sites with suitable soils to withstand the seismic hazard potential found in Southcentral Alaska using USGS Time-Independent Probabilistic Seismic Hazard Maps (2 Percent Probability of Peak Ground Acceleration in 50 Years), and soils mapping;

- Construction/Operations Planning: Closest proximity to critical infrastructure using Alaska Department of Transportation and Public Facilities (ADOT&PF) road maps, sites with terrain that would not require extensive earthwork by using the NASA ASTER 30-meter Digital Elevation Model;

- Land Use: Avoiding Native allotments (using Bureau of Land Management [BLM] mapping), state and federal conservation system units (i.e. State Parks, CHAs, SGRs, National Parks, Wildlife Refuges, wilderness areas, etc.), National Forest, National Park, Wilderness areas, and NWRs;

- Ecology: Sites that have few or no wetlands based on a review of United States Fish and Wildlife Service (USFWS) National Wetland Inventory maps;

- Recreation areas: Sites that avoided recreation areas using Alaska Department of Natural Resources (ADNR) mapping; and

- Population Density: Sites that avoided densely populated areas using U.S. Census Bureau data (2010 Census Blocks).

The feasibility study identified other serious flaws across a broader list of LNG design, marine terminal design, environmental permitting, pipeline routing, and geotechnical criteria. These criteria are listed in Table 10.3.2-1. Sites were compared in a manner that examined whether sites were inferior to one another for each of the criteria listed in the following table. Sites with a higher number of major considerations (i.e., serious flaws or potential exclusion factors) were progressively eliminated from further consideration.

The final analysis incorporated the cost and schedule implications of using a particular site, as well as the associated cost and schedule risks.

TABLE 10.3.2-1

Feasibility Study Criteria Evaluated for the Project

Category	Criteria	Flaw Analysis Considerations [a]
Facility Siting Criteria	Pipeline length	Increased pipeline lengths generally result in increased environmental impacts (every additional mile of pipeline results in approximately 20 acres of impact to environmental resources, not including access roads, pipe and contractor yards, and other associated facilities required as length is increased. Additional compressor stations are required if 50 or more miles are added). The longest pipeline routes would be considered a potential exclusion factor when compared to others.
	Distance from shore to 40-foot depth	Determines the potential need for dredging and dredge disposal, length of trestle, and navigational constraints. Sites that would require the most dredging for operations purposes (when compared to others) were considered to have a potential exclusion factor since this would be an ongoing operational impact that other sites wouldn't have, and thus would pose a schedule risk due to a lengthy regulatory process. Dredging for construction was not considered a potential exclusion factor because the impact would only be for the duration of construction.
	Known contamination areas	Potential environmental effects due to constructing in contaminated soils/sediments. Sites with known contamination that would require that the contamination be addressed prior to site construction were considered inferior to those sites that did not have such contamination issues.
	Presence of infrastructure or other industrial/port facilities	Sites without any nearby roads, airports, ports, or even rail facilities were considered to have a potential exclusion factor when compared to sites that had such facilities nearby or adjacent. Sites without would be required to develop those facilities to support construction (operations are addressed later in this table).
	Presence of populated areas	Sites that would relocate or heavily affect a town or city were considered inferior sites when compared to those sites that did not require such an impact to a heavily populated area.
	Presence of an airport within 1.5 miles	Commercial airports within 1.5 miles of a Liquefaction Facility require Federal Aviation Administration approval to ensure that there are no restrictions to flight paths to/from the airport and that the facility is not within an active approach.
	Presence of Waters of the United States	Amount of wetlands and waterbodies on the site. In keeping with the USACE review of site impacts (CWA 404 (b)(1)(b) review), sites with the most permanent impact to waters of the United States or ponds, streams, or other waterbodies were considered to have a potential exclusion factor for this criterion.
	Site preparation constraints (relative amount of grading, blasting, demolition of structures, and disposal of rock and buildings).	Steep bluffs, hilly terrain and/or rock presence would require a larger footprint to prepare the site for facility construction. Removal of waste rock, soil, and other material creates a larger environmental impact with the need for disposal sites. Existing structures on the site would require demolition and disposal. Sites that required a lot of leveling, filling, or demolition and disposal were considered inferior to those sites that did not have these requirements to build facilities on them.
Facility Operations	Presence of ice/snow	Heavy snow and marine ice conditions could restrict operations and/or the number of LNGCs per month in winter months. Sites that would have ice build-up or would become iced in were considered inferior to those sites that did not have such winter constraints.

TABLE 10.3.2-1

Feasibility Study Criteria Evaluated for the Project

Category	Criteria	Flaw Analysis Considerations [a]
	Remoteness of site (whether a camp would be required or operations staff could be integrated into the community)	This criterion examined whether the site was proximate to developed communities to support housing operational staff as opposed to developing more land on the site for worker housing during operations. Sites that were without or were too far removed from communities were considered to have a potential exclusion factor for this criterion based on the additional required footprint and associated impacts and costs.
	Infrastructure to support operations	As discussed previously, the presence of infrastructure is critical for operations of the facility. Sites that lacked existing infrastructure were considered to have a potential exclusion factor from a siting perspective compared to sites that had such infrastructure.
Public land use conflicts	Conflict with land use planning	Changing the land use in an area that was set aside for conservation was considered a potential exclusion factor when compared to sites that were within an area set aside for industrial development and inferior to areas with no specific land use designations.
	Alaska National Interest Lands Conservation Act (ANILCA) Conservation System Units	Sites that entered public lands protected under ANILCA were considered to have an exclusion factor. Sites that could create indirect impacts to ANILCA lands were considered to be high risk and inferior to sites without this constraint.
Facility Permitting	Facility Permitting	Permitting feasibility was assessed for each site based on the impacts to the environment and public land, as well as socioeconomic impacts. Sites with higher risk of permitting were considered inferior sites to those with lower risks. In addition, adjacent air emissions were considered for each site to assess compatibility with proposed Liquefaction Facility emissions.
Protected Species	Environmental Species Act (ESA) - or state-designated critical habitat and listed species jeopardy impacts from construction or operations impacts.	Sites that could cause a jeopardy take of a listed species were considered to have an exclusion factor. Sites that would have impacts to listed species habitat without a jeopardy take were considered risks to the schedule for construction and were inferior to those sites that did not have such constraints.
Geological Hazards	Fault lines (within 0.25 mile) Volcanos Landslide potential Tsunamis	Construction and operation hazards, design considerations, and operational constraints of the proposed new infrastructure were assessed with respect to the risk of these geologic hazards to design costs and operational risk. Sites with impacts from these features were inferior to those sites that did not have impacts from these criteria.
Vessel Conflicts	Existing vessel traffic Width of waterway to accommodate LNGCs	Waterbodies adjacent to the proposed site that were narrow were considered to have a potential exclusion factor for LNGC operations. A safety/exclusion zone around laden LNGCs would be a requirement of the USCG, and this would impede existing vessel traffic and also impeded LNGC schedules to/from the site. Such sites were considered inferior to those sites on wider waterbodies that had no restrictions to traffic flow.

[a] A criterion was considered a serious or potential exclusion factor if the presence of that criterion has significant impacts, has significant regulatory uncertainty, or adds significant risk to cost and schedule based on the potential impacts of the Project at that location to that criterion. For example, the distance from shore to the 40-foot contour results either in a long, expensive trestle and cryogenic pipeline to move LNG from the tanks to the ships, or that dredging and dredge disposal would be required to shorten the trestle and cryogenic pipeline to increase site suitability. In either situation, the increased costs (longer trestle) or permitting risk (dredging for operations) were considered inferior to those sites that had shorter distances to the 40-foot depth contour.

10.3.2.2.2 Screening Study

A multidisciplinary team, utilizing a GIS database created from extensive agency, public, and prior project data evaluated the impact of each site in relation to the prior criteria and made a qualitative comparison of the impacts of each site to those criteria. Sites with the largest number of negative impacts to the siting criteria were eliminated from further consideration or analysis. The top eight sites were then carried forward into the next level of analysis, which was the feasibility study. See Section 10.3.2.3, Screening Analysis, for a discussion on how the study was conducted.

10.3.2.2.3 Feasibility Study

The second study was a feasibility assessment of the sites using more-detailed desk and field reconnaissance information to determine the potential ability to design, permit, build, and operate a Liquefaction Facility at each location. There were several rounds of assessments completed, each round examining a site in more detail if there were no potential exclusion factors identified, using publicly available and prior project data to determine if there were serious flaws with the location for each criterion. Additionally, in the feasibility study, the pipeline component of the LNG terminal was examined to determine if there were potential exclusion factors associated with routing the pipeline to the short-listed site. The results of the feasibility study identified the Applicants' proposed alternative Liquefaction Facility site.

10.3.2.3 Screening Analysis

10.3.2.3.1 Study Sites

Potential sites were identified in Southcentral Alaska by first identifying areas where sites would not be located: within state or federal conservation system areas (e.g., parks, forests, wildlife refuges), within 1.5 miles of an airport, within an ADNR/Alaska Department of Fish and Game (ADF&G) wildlife management or game management area, or within a volcanic hazard zone. After excluding these areas along the Southcentral Alaska coast (i.e., the Cook Inlet, Prince William Sound, Seward, and Whittier areas), 24 potential sites were identified for the screening analysis (see Table 10.3.2-2 and the maps in Appendix B).

TABLE 10.3.2-2

Potential Sites Evaluated for Siting of the Liquefaction Facility

Sites Evaluated[a]	Borough/Census Area	Major Waterway	General Site Description
Anderson Bay	Valdez-Cordova	Valdez Arm (Prince William Sound)	Undeveloped area near the mouth of Valdez Arm
Boulder Point	Kenai Peninsula	Northern Cook Inlet	Undeveloped area approximately 6 miles northeast of Nikiski
Cape Starichkof	Kenai Peninsula	Central Cook Inlet	Undeveloped area approximately 6 miles north of Anchor Point, near the Sterling Highway
Comfort Cove	Valdez-Cordova	Prince William Sound	Undeveloped area northeast of Gravina Point
Fish Bay	Valdez-Cordova	Prince William Sound	Undeveloped area near Port Fidalgo
Gravina Point	Valdez-Cordova	Prince William Sound	Undeveloped area near Gravina Island
Harriet Point Area	Kenai Peninsula	Central Cook Inlet	Undeveloped area north of the Kasilof River

TABLE 10.3.2-2

Potential Sites Evaluated for Siting of the Liquefaction Facility

Sites Evaluated[a]	Borough/Census Area	Major Waterway	General Site Description
Jack Bay	Valdez-Cordova	Valdez Arm (Prince William Sound)	Undeveloped area near the mouth of Valdez Arm
Homer Region	Kenai Peninsula	Southern Cook Inlet	Undeveloped area north of Homer, along the Sterling Highway
Kalgin Island	Kenai Peninsula	Central Cook Inlet	Undeveloped island in the middle of Cook Inlet
Kasilof South	Kenai Peninsula	Central Cook Inlet	Undeveloped area along Cohoe Loop Road
Nikiski North[b]	Kenai Peninsula	Central Cook Inlet	Undeveloped area north of the industrial area of Nikiski
Nikiski[b]	Kenai Peninsula	Central Cook Inlet	Industrial area along the Kenai Spur Highway
Ninilchik South	Kenai Peninsula	Central Cook Inlet	Relatively undeveloped area along the Sterling Highway
North Foreland	Kenai Peninsula	Northern Cook Inlet	Undeveloped area approximately 4 miles southwest of Tyonek
Old Alpetco Industrial Site	Valdez-Cordova	Prince William Sound	Industrial area along Richardson Highway, near the Port of Valdez and airport
Point Mackenzie	Matanuska-Susitna	Knik Arm (Cook Inlet)	Undeveloped area across Cook Inlet from Elmendorf Air Force Base
Robe Lake	Valdez-Cordova	Valdez Arm (Prince William Sound)	Developed area at the head of Valdez Arm, along the Richardson Highway
Seward	Kenai Peninsula	Resurrection Bay	Industrial area across Resurrection Bay from Seward
Valdez Marine Terminal	Valdez-Cordova	Prince William Sound	Industrial area east of the Alyeska Pipeline Terminal, across Valdez Arm from Valdez
West Foreland	Kenai Peninsula	Central Cook Inlet	Undeveloped area directly across Cook Inlet from Nikiski
Whittier A	Valdez-Cordova	Passage Canal (Prince William Sound)	Industrial area at the head of Passage Canal
Whittier B	Valdez-Cordova	Passage Canal (Prince William Sound)	Undeveloped area across Passage Canal from Emerald Island
Whittier C	Valdez-Cordova	Blackstone Bay (Prince William Sound)	Undeveloped area south of Emerald Island on Blackstone Bay

Notes:

[a] During the course of the screening analysis, the locations of several sites were modified: Anderson Bay, Cape Starichkof, Kasilof South, Kenai (Nikiski), North Foreland, Robe Lake, and Seward.

[b] Two sites were evaluated in proximity to Nikiski, one encompassing the existing industrial sites and the other farther north near the Nikiski school (Nikiski North).

10.3.2.3.2 Screening Results

Based on the analysis of the criteria identified in Section 10.3.2.3, the multidisciplinary teams assessed and eliminated 16 sites that had exclusion factors for one or more criteria. In general, the sites were found to be impracticable because of water depth near the site, constraints with incompatible land use such as using an area designated as conservation land, lack of existing infrastructure to support construction and operations, and conflicts with existing vessel traffic in the waterbody leading to the site or with ice cover during the winter that would limit site use. Table 10.3.2-3 provides a summary of the major exclusion factors with each site that was eliminated from further analysis. A detailed analysis of all criteria was not undertaken once a site was deemed infeasible during screening.

TABLE 10.3.2-3

Sites Excluded from Further Analysis

Site	**Major Reasons for Exclusion from Further Analysis**[a]
Comfort Cove	• Incompatible land use/land ownership because the site is located on U.S. National Forest land and surrounded by Native land used for subsistence activities; • The pipeline to the site would traverse large tracts of conservation land through undeveloped areas; • There is little existing infrastructure at the site, so this would require building roads, airstrips, material borrow sites, and potentially other utilities from the site to the nearest infrastructure network. To do this would require crossing Native allotments and public land that is designated for conservation purposes.
Boulder Point	• There is incompatible land use/land ownership because the site is located on and surrounded by Cook Inlet Region, Inc. (CIRI) land; • Extensive shallow water (approximately 0.7 mile to reach a depth of 60 feet) is present requiring dredging to reduce trestle and cryogenic pipeline length; • There are high bluffs at the site requiring extensive grading and disposal with a high potential for rock and large rock removal (large boulders are present in Cook Inlet near the site and along the shoreline); and • A large amount of boulders is present in Cook Inlet (and potentially in the cliffs at the site) that would necessitate blasting to move them (they can be large as a house) or require extensive dredging to move them.
Fish Bay	• There is incompatible land use/land ownership because the site is on Native Village (Tatitlek) land; • The pipeline to the site would traverse large tracts of conservation land through undeveloped areas; and • There is little existing infrastructure at the site, so this would require building roads, airstrips, material borrow sites, and potentially other utilities from the site to the nearest infrastructure network. To do this would require crossing Native allotments and public land that is designated for conservation purposes.
Gravina Point	• There is incompatible land use/land ownership because the site is located on state land, and surrounded by Regional Corporation and Native Village (Tatitlek) land as well as U.S. National Forest land; • The pipeline to the site would traverse large tracts of conservation land through undeveloped areas; and • There is little existing infrastructure at the site, so this would require building roads, airstrips, material borrow sites, and potentially other utilities from the site to the nearest infrastructure network. To do this would require crossing Native allotments and public land that is designated for conservation purposes.
Harriet Point	• Geologic hazards exist with the close proximity of Mt. Redoubt; • Extensive shallow water is present (approximately 7.4 miles to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length; and • Incompatible land use/land ownership; the site is located on or surrounded by Native Regional Corporation and Native Village (Tatitlek) land.

TABLE 10.3.2-3

Sites Excluded from Further Analysis

Site	Major Reasons for Exclusion from Further Analysis[a]
Jack Bay	• There is incompatible land use/land ownership because the site is located on U.S. National Forest land; • The pipeline to the site would traverse large tracts of conservation land through undeveloped areas, and be required to cross a Wild and Scenic River that would result in schedule delays. It would also cross a high-risk area for cost and schedule adherence through Thompson Pass (See section on Anderson Bay); • Vessels to the site have to pass through a narrows, which would result in vessel control point conflicts with Valdez vessel traffic (and with the LNGCs going to the site); and • There is little existing infrastructure at the site, so this would require building roads, airstrips, material borrow sites, and potentially other utilities from the site to the nearest infrastructure network. To do this would require crossing Native allotments and public land that is designated for conservation purposes.
Homer Region	• There is incompatible land use because the site is in, or adjacent to, the Kachemak Bay and/or Anchor River and Fritz Creek Critical Habitat Area (CHA), depending on the exact location; • Extensive shallow water is present (approximately 5 miles to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length; • A high amount of wetlands is present (approximately 40 percent of the area); • Any pipeline to reach this area would require additional compression and pipeline impacts that would cross or impact more conservation and CIRI and Seldovia Native Village Corporation and/or Village land and Native allotments; and • Use of this site would result in potential conflicts with the current land use (industrial versus recreational use).
Kalgin Island	• Extensive shallow water is present (approximately 2.4 miles to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length; • The location is remote, requiring additional footprint for airstrip and ferry access for personnel both during construction and operations; • The location would be on a portion of the island with bird nesting habitat, both on- and offshore of the island, in several seasons; • The site is within 25 miles of Mount Redoubt; • There is extensive subsistence use on the island (clamming, hunting, fishing [setnet] and berry picking; and • There are setnet fish leases on the west side of island, adjacent to the site.
Nikiski North	• There is incompatible land use/land ownership because the site is located on and surrounded by CIRI and Native Village (Salamatof) land; • The location is north of and distant from existing industrial infrastructure and utilities; and • The site has extensive shallow water (approximately 1 mile to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length.
Old Alpetco Industrial Site	• The site has extensive shallow water (approximately 1 mile to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length; • The pipeline would be required to cross a Wild and Scenic River that would result in schedule delays and a high-risk area for cost and schedule adherence through Thompson Pass (see section on Anderson Bay); • The site is in proximity of the Port of Valdez, resulting in potential ship traffic conflicts; and • The site is in proximity of a public airport, resulting in potential conflicts.

TABLE 10.3.2-3

Sites Excluded from Further Analysis

Site	Major Reasons for Exclusion from Further Analysis[a]
Point Mackenzie	• There is incompatible land use/land ownership because the site is located on Native Village (Knik) lands; • LNGC traffic into this portion of Upper Cook Inlet would cause conflicts with vessels moving into and out of the Port itself as well as potentially impacting traffic patterns to the Port of Anchorage and points north (exclusion zones around laden carriers, see section on Anderson Bay); • The site's high bluffs would require extensive site grading, and the shoreline has high erosion rates; • There is extensive shallow water (approximately 1.6 miles to reach a depth of 60 feet) requiring dredging to reduce trestle and cryogenic pipeline length; • The site is in the presence of ESA Beluga Whale CHA 1, which would require extensive measures to protect the beluga whale during both construction and operations, resulting in schedule risk and potential cost implications; and • Presence of heavy ice concentrations in winter combined with strong currents and presence of rock outcroppings resulted in marine vessel risks.
Valdez Marine Terminal	• There are air emissions constraints at the proposed site due to the presence of the existing Valdez oil terminal and prevailing wind direction and topography; • There is steep topography on the site requiring extensive blasting and grading to level or bench the site resulting in extensive fill in Prince William Sound; • There are vessel safety concerns in Valdez due to the control points of Hinchinbrook Entrance and the Valdez Narrows (see section on Anderson Bay); • The pipeline would be required to cross a Wild and Scenic River that would result in schedule delays and a high-risk area for cost and schedule adherence through Thompson Pass (see section on Anderson Bay); and • Concerns over the application of C.F.R. 193 to an integrated Valdez Marine Terminal and LNG terminal.
West Foreland	• There is incompatible land ownership because the site is located on and surrounded by CIRI and Native Village (Salamatof) lands; • Moving the site to avoid Native allotments and Regional and Village Corporation lands puts the site into the projected mud/lava flows of Mount Redoubt, an active volcano, as well as faults nearby; • There is extensive shallow water (approximately 1.5 miles to reach a depth of 60 feet), requiring dredging to reduce trestle and cryogenic pipeline length; and • There are potential conflicts with the current land use (industrial versus recreational use).
Whittier A	• There is incompatible land use/land ownership because the site is located on and the associated pipeline route would traverse the Chugach National Forest; • The pipeline would be required to tunnel through the mountains to get to the bay, which would be technically cost prohibitive; and • There is a potential conflict with recreational users of the bay and cruise ship traffic because of the narrow nature of the waterbody.
Whittier B	• There is incompatible land use/land ownership because the site is located on and the associated pipeline route would traverse the Chugach National Forest; • The pipeline would be required to tunnel through the mountains to get to the bay, which would be technically cost prohibitive; • There is a potential conflict with recreational users of the bay and cruise ship traffic because of the narrow nature of the waterbody; and • Its location along north side of the bay on steep terrain would require extensive blasting and leveling or benching of the site and disposal in the bay.

TABLE 10.3.2-3

Sites Excluded from Further Analysis

Site	Major Reasons for Exclusion from Further Analysis[a]
Whittier C	• There is incompatible land use/land ownership because the site is located on and the associated pipeline route would traverse the Chugach National Forest; • The pipeline would be required to tunnel through the mountains to get to the bay, which would be technically cost prohibitive; and • There is a potential conflict with recreational users of the bay and cruise ship traffic because of the narrow nature of the waterbody.

[a] With respect to issues related to the associated pipeline to reach the proposed site, the primary focus was on exclusion factors along the pipeline routing, at the site, or between the site and existing infrastructure that would be necessary to operate the facility at the site. Crossing or direct impacts to Native allotments and conservation land that would trigger a Bureau of Indian Affairs or ANILCA process, respectively, was considered too long-term to meet the Project schedule objectives and therefore considered an exclusion factor.

10.3.2.3.3 Sites Selected for Feasibility Analysis

As a result of the screening analysis, the sites in Table 10.3.2-4 were evaluated in the more-detailed feasibility study.

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
Setting	Undeveloped Accessible by float plane or watercraft only Receives significant and frequent snowfall Area is free of sea ice, heavy snow (290 inches per year), rain, and wind impact vessel operations during winter	Undeveloped The general area has a high subsistence use. Low amount of annual snowfall Some ice in trestle area to be accounted for, but less than to the north Weather window is reasonable for barge transport requirements	Undeveloped South of the Kasilof River mouth Low amount of annual snowfall Some ice in the trestle area to be accounted for, but less than to the north Weather window is reasonable for barge transport requirements	Industrial; the Kenai Peninsula Borough Comprehensive Plan (2005) designates the area as an industrial site Low amount of annual snowfall Some ice in trestle area Weather window is reasonable for barge transport requirements	Undeveloped; one mining permitted facility that engages in granular material extraction was identified Low amount of annual snowfall Some ice in trestle area to be accounted for, but less than to the north Weather window is reasonable for barge transport requirements	Largely undeveloped except for several oil and gas wells, well pads, and timber roads produced from contract logging More snow than the at east side of Cook Inlet and less than at Prince William Sound Weather window is impacted by ice conditions and heavier snow than at the East side of Cook Inlet	Developed Receives significant and frequent snowfall Area is free of sea ice, heavy snow (290 inches per year), rain, and wind impact vessel operations during winter	Industrial Low amount of annual snowfall Remains free of ice year-round Weather window is reasonable for barge transport requirements
Major Pipeline Delivery Option	The major pipeline delivery route option to Valdez is approximately 808 miles long and has a considerable amount of collocation with the Trans-Alaska Pipeline System (TAPS) and a highway system for almost its entire length. However, the new pipeline	The major pipeline delivery route option to this site is the same as described for Nikiski. However, the route would be a minimum of 60 miles longer than to Nikiski (a minimum of 851 miles) and would require crossing the Kenai River. An additional compressor station	The major pipeline delivery route option to this site is the same as described for Nikiski. However, the route would be a minimum of 25 miles longer than to Nikiski (a minimum of 816 miles) and would require	The major pipeline delivery route option to Cook Inlet in the Nikiski area is located primarily within existing corridors (within 1 mile of existing linear features) and is approximately	The major pipeline delivery route option to this site is the same as described for Nikiski. However, the route would be a minimum of 49 miles longer than to Nikiski (a minimum of 840 miles) and would require crossing the Kenai River.	The major pipeline delivery route option to the north side of Cook Inlet is the shortest option evaluated at approximately 761 miles long. The route does cross active faults and extensive	The major pipeline delivery route option to this site is the same as described for Anderson Bay.	The major pipeline delivery route option to this site is the longest option evaluated at approximately 871 miles long. Unlike the Cook Inlet option, it crosses through the Chugach National Forest. An additional compressor

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Nikiski**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
	could not be within the TAPS ROW (TAPS offset requirement) and would require crossing numerous federal (Department of Defense and conservation) lands. Unlike the Cook Inlet option, the route crosses two rivers classified as Wild and Scenic Rivers (Gulkana and Delta rivers), so designated since TAPS was built. It also crosses numerous active military lands, some with contaminated site issues, including Fort Wainwright, Eielson Air Force Base, and Fort Greely. It crosses National Forest land where there is no existing corridor and Thompson Pass, a very steep mountainside with constructability concerns and a limited amount of space for a new pipeline. Crossing	would be required. After crossing Cook Inlet, additional routing through the Kenai Peninsula would be necessary, including through or around Native allotments and public lands.	crossing the Kenai River. After crossing Cook Inlet, additional routing through the Kenai Peninsula would be necessary, including through or around Native allotments and public lands.	807 miles. Approximately 590 miles of this are collated with TAPS, and proximate to the Parks Highway. The route requires crossing Cook Inlet, including through Beluga Whale ESA CHA 2, active faults, extensive wetlands, and is in close proximity to DNPP. It also crosses a predominance of State of Alaska and BLM lands.	Potentially a new compressor station would be required on the Kenai Peninsula. After crossing Cook Inlet, additional routing through the Kenai Peninsula would be necessary, including through or around Native allotments and public lands.	wetlands; the route also crosses a predominance of State of Alaska and BLM lands.		station over either the Valdez or Nikiski routes would be required. Other constraints along the route include a narrow workspace next to a railroad, traversing the east side of Anchorage, and the steep terrain of bordering mountains along the Seward Highway.

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
	here is steeper than at Atigun Pass.							
Land Use	Lands within the site are owned by the State of Alaska and managed by ADNR. The majority of land surrounding the site is within the Chugach National Forest, and the small amount of land contiguous to the site on the east and west sides that is not within the Chugach National Forest is owned by the State of Alaska (FERC, 1995). The site is located approximately 6.3 miles from Fort Liscum, the nearest populated area, and over 20 miles to Valdez.	Generalized land use within the site is categorized by residential, commercial, improved, and vacant parcels. Land ownership is a mixture of private and state property holders. The site is located approximately 5.3 miles from Happy Valley, the nearest populated area.	Land use within the site includes a mixture of residential, commercial, institutional, and public lands. Land ownership is a mixture of private, state, borough, Native Corporation, and federal land. The site is located approximately 2.8 miles from Cohoe, the nearest populated area.	Generalized land use in the area includes residential, commercial, industrial, improved, and vacant land parcels. Land ownership is a mixture of private, state, borough, and Native Village land. The site is located approximately 1.8 miles from the populated area of Nikiski.	Land use within the site includes residential, commercial, institutional, improved, and vacant land parcels. Land ownership is a mixture of borough, state, Native Village, Native Corporation, and private landowners. The site is located approximately 2.4 miles from Ninilchik, the nearest populated area.	Land use within the site is classified as vacant, Native-patented, or interim conveyance lands. Land ownership consists entirely of Tyonek Native Village land. The site is located approximately 1.6 miles from the populated area of Old Tyonek.	Land use within the site is a mixture of residential, commercial, public, and light and heavy industrial zoning classifications. Land ownership consists of private, city, and state land. The site is located approximately 6 miles from Valdez, the nearest populated area.	Land use within the site is predominantly commercial/ industrial. Land ownership consists of private, city, and state land. The site encompasses the Seward Marine Industrial Center (SMIC) and additional areas slated for development. The site is located approximately 3.2 miles from the populated area of Seward.
Special Use Areas	There are no identified special use areas, or other legislatively designated lands, within the site boundary or a 0.5-mile buffer zone.	Located adjacent to the Stariski State Recreation Site	Clam Gulch CHA is located along the shoreline and it is in proximity to Kasilof River Special Use Area.	There are no identified special use areas, or other legislatively designated lands, within the site boundary or a	Clam Gulch CHA is located along the shoreline and it is in proximity to Deep Creek State Recreation Area (SRA).	There are no identified special use areas, or other legislatively designated lands, within the site boundary or a	There are no identified special use areas, or other legislatively designated lands, within the site boundary or	The state legislature has designated state-owned submerged lands and tidal lands in Resurrection Bay as Special

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Nikiski**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
				0.5-mile buffer zone.		0.5-mile buffer zone.	a 0.5-mile buffer zone.	Use Land. The city owns the tidelands at the head of Resurrection Bay that are immediately adjacent to Seward extending to the mouth of the Resurrection River and Fourth of July Creek, which is immediately south of the site.
Recreation	In addition to sport fishing, Anderson Bay is listed as a high-recreation use area (May–September); however, the area is remote with no roads crossing the site and access primarily limited to small boats and other marine watercraft access.	Areas adjacent to the site location are used for recreational purposes (e.g., clams, recreational trails).	The mouth of the Kasilof River, ~2 miles northeast of the site boundary, is a premier fishing destination for recreational users on the Kenai Peninsula.	Recreation and tourism are not significant in this industrial area.	The site is located between Deep Creek to the north (approximately 0.9 mile) and the Ninilchik River to the south (approximately 2.2 miles), which are highly popular for recreational and commercial fishing, Kenai Peninsula residents, and tourists.	Subsistence is the primary use of the land within the general area associated with the Native Village of Tyonek. Recreational uses such as sport fishing and hunting exist, but are limited due to the relative inaccessibility of the area.	Areas surrounding the site have a high recreational value.	Seward is a high-value recreation area and is considered the gateway to Kenai Fjords National Park. Many tourist trips are based in Seward and use Resurrection Bay to view glaciers and whales, and for fishing and touring.
Geologic Hazard	There is the medium potential for seismic events	There is the potential for seismic events of varying	There is the potential for seismic events	There is the potential for seismic events	There is the potential for seismic events of	Five volcanos border the west side of Cook	There is the potential for seismic events	There is the potential for seismic events

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
NOTE: All of Southcentral Alaska has higher seismicity than northern or central Alaska. The epicenter of the 1964 earthquake that damaged Anchorage was in the Prince William Sound area.	of varying magnitude in the region. Historical activity includes submerged landslides and tsunami generation within Valdez Arm and Port Valdez. Historical records indicate high wave run-ups related to tsunamis at the site. The 1964 earthquake triggered a tsunami that destroyed the Seward and Valdez docks. Bedrock provides suitable material to design for seismic events.	magnitude in the region. Short-duration, low-magnitude tremors occur commonly throughout the Cook Inlet region. Historical activity includes a middle range of tsunami wave heights. Ash fall from volcanos west of Cook Inlet are possible at this location. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.	of varying magnitude in the region. Short-duration, low-magnitude tremors occur commonly throughout the Cook Inlet region. The cliff provides a natural buffer and historical records indicate no observed wave run-ups related to tsunamis. Ash fall from volcanos west of Cook Inlet are possible at this location. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.	of varying magnitude in the region. Short-duration, low-magnitude tremors occur commonly throughout the Cook Inlet region. The cliff provides a natural buffer and historical records indicate no observed wave run-ups related to tsunamis. Ash fall from volcanos west of Cook Inlet are possible at this location. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.	varying magnitude in the region. Short-duration, low-magnitude tremors occur commonly throughout the Cook Inlet region. The cliff provides a natural buffer and historical records indicate no observed wave run-ups related to tsunamis. Ash fall from volcanos west of Cook Inlet are possible at this location. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.	Inlet and have been active for some time, as indicated by numerous buried ash layers in the surrounding soils. Several eruptions have occurred over the last quarter-century. The most recent eruption was Mount Redoubt in 2009. There is also the potential for seismic events of varying magnitude in the region. Short-duration, low-magnitude tremors occur commonly throughout the Cook Inlet region. The cliff provides a natural buffer and historical records indicate no observed wave run-ups related to tsunamis.	of varying magnitude in the region. Historical activity includes submerged landslides and tsunami generation within Valdez Arm and Port Valdez. Historical records indicate high wave run-ups related to tsunamis. The 1964 earthquake triggered a tsunami that destroyed the Seward and Valdez docks. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.	of varying magnitude in the region. Historical activity includes submerged landslides and tsunami generation. The 1964 earthquake triggered a tsunami that destroyed the Seward and Valdez docks. Soils are shallow with consolidated material that can be tied to foundation design for seismic events.

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Nikiski**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
						Ash fall from volcanos west of Cook Inlet are possible at this location. Unconsolidated soils on the site would require pilings tied to bedrock or suitable consolidated material to design for seismic events.		
Vegetation	Heavily forested	Most of the site consists of forested land and wetlands.	Substantial areas of forested land	Substantial areas of disturbed or cleared areas in industrial locations. Wooded areas are also present.	Most of the site consists of deforested land.	Primarily forested land	Forested and developed lands	Developed with cleared areas

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
Protected Species	Steller sea lions use Prince William Sound, but there is no Critical Habitat (CH) designated in Prince William Sound or Cook Inlet.	Steller sea lions use Prince William Sound, but there is no CH designated in Prince William Sound or Cook Inlet. Belugas are found in Cook Inlet, but this area is outside the designated CH.	Beluga whale ESA CHA2 is located offshore.	Beluga whale ESA CHA 2 is located offshore.	Steller sea lions use Prince William Sound, but there is no CH designated in Prince William Sound or Cook Inlet. Belugas are found in Cook Inlet, but this area is outside the designated CH.	Beluga whale ESA CHA 2 is located offshore.	Steller sea lions use Prince William Sound, but there is no CH designated in Prince William Sound or Cook Inlet.	Steller sea lions and humpback whales use Prince William Sound, but there is no CH designated in Prince William Sound or Cook Inlet.
Fishery Resources	Short Creek is a small stream that supports anadromous salmonids and is completely enveloped within the site boundary. The stream serves as spawning grounds for chum and pink salmon. This stream would need to be removed or rerouted. Anadromous streams Confusion Creek and George Creek are also located adjacent to the site.	The site is close to tributaries to Stariski Creek, a stream that supports anadromous salmonids. One unnamed tributary is located on site. Stariski Creek and its tributaries serve as both spawning and rearing grounds for fish species including coho, chinook, and pink salmon.	There are no streams that support anadromous salmonids on site or potential spawning areas identified. The coastline on the west side has nearshore and offshore fishery leases, as well as tidal leases granted by ADNR.	There are no streams that support anadromous salmonids on site or potential spawning areas identified. During the salmon spawning season, the shoreline has setnet leases present.	There are no streams that support anadromous salmonids on site or potential spawning areas identified. This site is in proximity to Deep Creek, a stream that supports anadromous salmonids. Deep Creek and its tributaries serve as both spawning and rearing grounds for fish species including coho, chinook, and pink salmon.	There are no streams that support anadromous salmonids located at the site. An anadromous stream segment, Tyonek Creek, is found adjacent to the site that provides feeding, spawning, and/or rearing habitat for pink and silver salmon in the lower, middle, and upper stream extent.	The site encompasses small streams that serve as spawning and rearing grounds for several fish species including coho, sockeye, chum, pink salmon, and Dolly Varden with an occasional king salmon feeding and present in local waters. There are five distinct anadromous stream segments located within the site and	There are three streams that support anadromous salmonids on site, including Fourth of July Creek and Spring Creek. These streams serve as spawning and feeding areas for coho, chum, and pink salmon.

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Nikiski**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
						Salmon is the number one subsistence resource in the Village of Tyonek.	surrounding area.	
Surface Water[a]	Short Creek is a small stream completely enveloped within the site. Terminal Creek and Strike Creek might also be present. Confusion Creek and George Creek are located adjacent to the site.	Nine small surface waterbodies and an unnamed tributary to the North Fork of the Anchor River were identified on the site. Several segments of an unnamed tributary to Stariski Creek are located adjacent to the site.	No significant surface water features were identified on the site. Adjacent surface features consist of a single, small 2.6-acre unnamed pond.	An unnamed pond along Bernice Lake Road is found on site. Bernice Lake is nearby. Other nearby surface waters include unnamed ponds, Cabin Lake, and a stream segment generated by the Bernice Lake outlet that discharges to Cook Inlet.	An unnamed tributary to Deep Creek was identified on the site and segments of Deep Creek are located adjacent to the site.	Eight waterbodies totaling 37 acres were identified on the site. Five waterbodies totaling 134 acres and two stream segments were identified on and adjacent to the site.	Stream segments of Robe River and Corbin Creek were identified on site. Stream segments of Robe River, Corbin Creek, Valdez Glacier Stream, and Slater Creek were identified adjacent to the site.	Surface waters identified on the site include: - Godwin and Spring Creek; - Fourth of July Creek; - Unnamed pond; and - Unnamed stream with upper extent terminating at the site. Adjacent to the site are various stream segments, including Fourth of July Creek and Godwin Creek, which discharge to Resurrection Bay.
Wetlands[a]	~7% of the site (Note: does not include the amount of marine habitat	Relatively extensive (~41% of the site)	The southeastern portion of the site is emergent	~2% of the site (Note: does not include any acreage	~14% of the site	~13% of the site (not including ponds	~8% of the site	~14% of the site

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
	that would be filled with rock removed from the site)		wetland vegetation. (~11% of the site). There is extensive use of the wetland habitat by wildlife (moose, birds).	affected by dredging during construction)		listed previously)		
Cultural Resources	No cultural resource sites have been reported.	No cultural resource sites have been reported.	No cultural resource sites have been reported.	One cultural resource site has been found, under SHPO evaluation.	No cultural resource sites have been reported.	Five reported cultural resource sites are present.	No cultural resource sites have been reported.	No cultural resource sites have been reported.
Air Quality	Approximately 165 miles from the nearest Class I air shed (DNPP) The existing Valdez oil terminal is adjacent to the site and would contribute to cumulative air emissions of a proposed LNG plant.	Approximately 32 miles from the nearest Class I air shed (Tuxedni National Wildlife Refuge [NWR]) No nearby major sources of air emissions	Approximately 43 miles from the nearest Class I airshed (Tuxedni NWR) No nearby major sources of air emissions	Approximately 54 miles from the nearest Class I air shed (Tuxedni NWR) The existing Tesoro refinery and Kenai LNG Plant are adjacent to the site. Also, the adjacent Agrium fertilizer plant has filed for restart but has not initiated any startup activity. Any of these facilities would be	Approximately 30 miles from the nearest Class I air shed (Tuxedni NWR) No nearby major sources of air emissions	Approximately 75 miles from the nearest Class I air shed (Tuxedni NWR) No nearby major sources of air emissions	Approximately 171 miles from the nearest Class I air shed (DNPP) The existing Valdez oil terminal is adjacent to the site and would contribute to cumulative air emissions of a proposed LNG plant.	Approximately 111 miles from the nearest Class I air shed (Tuxedni NWR) No major permitted sources nearby, but the cruise terminal is less than 10 miles away from the site

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Nikiski**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
				expected to contribute to cumulative emissions, although significant impact from multiple facilities simultaneously is unlikely.				
Contamination	No recorded contaminated sites were identified within the site boundary or a 0.5-mile buffer zone of the site.	No recorded contaminated sites were identified within the site boundary or a 0.5-mile buffer zone of the site.	No recorded contaminated sites were identified within the site boundary or a 0.5-mile buffer zone of the site.	Eight active and one closed ADEC clean-up sites are listed within the site boundary. A 0.5-mile buffer zone of the site encompasses an additional 10 sites (8 active, 2 cleanups complete).	No recorded contaminated sites were identified within the site boundary or a 0.5-mile buffer zone of the site.	One active ADEC contaminated site is located at the edge of the site boundary. The state lists this site as cleanup complete. No additional sites are located in a 0.5-mile buffer zone of the site.	One active ADEC contaminated site is located within the site boundary. No additional sites are located in a 0.5-mile buffer zone of the site.	There are five clean-up complete sites, with three that have institutional controls established by the state. No additional sites are located in a 0.5-mile buffer zone of the site.
Dredging and Sediment Disposal Options	Construction: Some level of dredging may be needed to unload LNG modules during site construction or due to other site constraints. Two Moon Bay has been identified as a potential dredge disposal area with	Construction: It is possible that dredging may be required to unload LNG modules during site construction or during installation of the Marine Terminal. Operations: Extensive shallow water is present—	Construction: Based on bathymetric information, dredging would likely be needed to support construction and the offloading of LNG modules. Operations: Extensive shallow water is	Construction: Dredging would likely be required for module offloading but would be allowed to in-fill after construction. Some onsite grading and excavation would be	Construction: Based on bathymetric information, dredging would be needed in support of unloading LNG modules during construction. Operations: Extensive shallow water is	Construction: Based on bathymetric data, it is expected that dredging would be required to unload LNG modules during facility and for Marine Terminal	Construction: Extensive dredging would be required to offload modules. A long trestle would be required for operations to avoid extensive dredging for operations. Two Moon Bay	Construction: Dredging would likely be required based on design features of the SMIC basin, the North Dock, East Dock, breakwater, and associated facilities at the existing industrial

TABLE 10.3.2-4

Descriptions of the Potential Alternative Liquefaction Facility Sites for the Project

Site Description	Anderson Bay	Cape Starichkof	Kasilof South	Nikiski	Ninilchik South	North Foreland	Robe Lake	Seward
	beneficial use application. Considerable rock blasting and excavation (~39 million cubic yards) removed from the site would be disposed along the shoreline at the site and on the site to create a dock and to bench the site for the plant. Operations: None anticipated	approximately 2.4 miles to reach a depth of 60 feet; potentially more than 2 million cubic yards of dredging.	present—approximately 3.8 miles to reach a depth of 60 feet; potentially more than 3.4 million cubic yards of dredging.	required, with a majority of the materials used on site after processing (granular material, sand, etc., for site use and concrete mixing). Operations: None anticipated	present—approximately 3.7 miles to reach a depth of 60 feet, potentially more than 3.3 million cubic yards of dredging.	construction and operations. Operations: Extensive shallow water is present—approximately 2.2 miles to reach a depth of 60 feet; potentially more than 1.9 million cubic yards of dredging.	has been identified as a potential dredge disposal area with beneficial use application. Operations: Depth to the 60-foot contour is approximately 2,000 feet, requiring approximately 1.5 million cubic yards of dredging. Also, LNG tanks would be almost 1 mile inland because of soil and foundation stability needs, resulting in considerable trestle and cryogenic pipeline length.	center. The existing site may serve as a potential or partial dredge disposal area with beneficial use application. Operations: Depth to the 60-foot contour is approximately 1,000 feet, requiring approximately 750,000 cubic yards of dredging.

[a] Based on preliminary desktop estimates

10.3.2.4 Feasibility Analysis

A multidisciplinary team conducted several rounds of analysis to reduce the number of potential sites from eight to a single site (proposed Applicants' alternative), based on an examination of the number and type of exclusion factors and serious flaws associated with each site as well as an assessment of the schedule and cost risks associated with each site. This resulted in the selection of the Applicants' proposed site (Nikiski).

In addition to the site evaluation work, three major delivery options (Mainline route alternatives) were identified to connect the GTP to the three regions (Prince William Sound, Seward, and Cook Inlet) of the remaining eight Liquefaction Facility site alternatives. The Mainline delivery options include:

- Cook Inlet Pipeline Delivery Alternative with variations for delivery to the west or east side of the Inlet;[14]
- Valdez Pipeline Delivery Alternative; and
- Seward Pipeline Delivery Alternative.

Maps of these alternatives are provided in Appendix B.

Potential exclusion factors using the following routing constraints were examined for each delivery alternative. This information was then combined with the site feasibility analysis to create an overall evaluation of each site alternative. Pipeline routing criteria included: avoidance of Native allotments and avoidance of National Parks, Wilderness areas, and NWRs. These land designations/ownerships were considered to require lengthy and complex permitting processes that introduced risk to schedule and compromised the Project's ability to fulfill the stated purpose and need. Additional pipeline routing criteria included avoiding the following:

- Designated Wild and Scenic Rivers;
- Known National Register of Historic Places (NRHP)-eligible sites;
- Towns, cities, and densely populated areas;
- Areas of steep mountainous terrain; and
- Laying the pipeline within rivers or streams, as opposed to crossing them (e.g., narrow valleys with little or no room except within a river or stream).

Some sites by themselves might be acceptable alternatives. However, when coupled with the pipeline, they no longer become viable alternatives, as discussed in the following section.

10.3.2.4.1 Feasibility Results

The results of the iterative analysis and risk assessment are provided in Table 10.3.2-5 and is followed by a discussion of the sites eliminated from consideration as the Applicants' proposed alternative.

[14] The Cook Inlet Pipeline Delivery Alternatives were part of early Project development. The Mainline route alternative to Cook Inlet has been further refined, as discussed in Section 10.4.2.3.

TABLE 10.3.2-5

Summary of Site Comparisons

Category	**Criteria**	**Nikiski (Applicants' proposed alternative)**	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
Facility Siting Criteria	Pipeline Length to site	Approx. 807 miles long, eight compressor stations	Approx. 4–5 miles longer than to the Nikiski site	Approx. 60 miles longer than to the Nikiski site Would require additional compression	Approx. 25 miles longer than to the Nikiski site	Approx. 50 miles longer than to the Nikiski site Would require additional compression	Approx. 40 miles shorter than to the Nikiski site	Approx. the same as to the Nikiski site	Approx. 70 miles longer than to the Nikiski site Would require additional compression
	Dredging	Construction: Approx. 1,400 feet to the 60-foot depth contour; dredging for a material offloading facility (MOF) proposed to require approximately 1.5 million cubic yards to be dredged Operations: None anticipated	Construction: Less than 500 feet to the 60-foot depth contour; minimal dredging required for a MOF. More than 39 million cubic yards of rock fill would be disposed of in Prince William Sound to build a marine terminal. Operations: None anticipated	Construction: Approx. 2.4 miles to reach a depth of 60 feet, potentially requiring more than 2 million cubic yards of dredging for construction Operations: An undetermined amount required for facility operations	Construction: Approx. 3.8 miles to reach a depth of 60 feet, potentially requiring more than 3.4 million cubic yards of dredging for construction Operations: An undetermined amount required for facility operations	Construction: Approx. 3.7 miles to reach a depth of 60 feet, potentially requiring more than 3.3 million cubic yards of dredging for construction Operations: An undetermined amount required for facility operations	Construction: Approx. 2.2 miles to reach a depth of 60' feet, potentially requiring more than 1.9 million cubic yards of dredging for construction Operations: An undetermined amount required for facility operations	Construction: Approx. 2,000 feet to reach a depth of 60 feet, potentially requiring more than 1.5 million cubic yards of dredging Operations: An undetermined amount required for facility operations Also LNG tanks would be almost 1 mile inland because of tank foundation stability	Construction: Approx. 1,000 feet to reach a depth of 60 feet, requiring approximately 750,000 cubic yards of dredging for construction Operations: An undetermined amount required for facility operations

TABLE 10.3.2-5

Summary of Site Comparisons

Category	Criteria	Nikiski (Applicants' proposed alternative)	Anderson Bay	Cape Starichkof	Kasilof South	Ninilchik South	North Foreland	Robe Lake	Seward
								requirements, resulting in a more than 1-mile-long trestle and cryogenic pipeline length.	
	Known contamination areas	Active and closed sites within the property boundary in various stages of cleanup	None identified	None identified	None identified	None identified	One active site on property No information on cleanup status	Active sites on property in various stages of cleanup	Three sites cleaned up, but treatment systems active on site
	Infrastructure constraints	None—adequate roads, airports, and ports nearby to support construction and operations	Site constrained; no roads nearby or nearby rail Some port capabilities nearby and an airport	Some: highway nearby by but no adequate ports or rail Airport nearby	Some, highway nearby by but no adequate ports or rail Airport nearby	Some, highway nearby by but no adequate ports or rail. Airport nearby	Site constraint, no major roads, rail, airports, or ports nearby	Close to highway, but no rail or major ports Airport nearby	Adequate port nearby, rail, and highway Airport nearby
	Presence of populated areas	The site is located approx. 1.8 miles from the populated area of Nikiski.	The site is located approx. 6.3 miles from Fort Liscum, the nearest populated area, and more than 20 miles from Valdez.	The site is located approx. 5.3 miles from Happy Valley, the nearest populated area.	The site is located approx. 2.8 miles from Cohoe, the nearest populated area.	The site is located approx. 2.4 miles from Ninilchik, the nearest populated area.	The site is located approx. 1.6 miles from the populated area of Old Tyonek.	The site is located approx. 6 miles from Valdez, the nearest populated area.	The site is located approx. 3.2 miles from the populated area of Seward.
	Wetlands and waterbodies	**Onshore:** approx. 16 acres	**Onshore:** approx. 60 acres	**Onshore:** approx. 330	**Onshore:** approx. 88	**Onshore:** approx. 112	**Onshore:** approx. 105	**Onshore:** approx. 64	**Onshore:** approx. 112

TABLE 10.3.2-5

Summary of Site Comparisons

Category	**Criteria**	**Nikiski (Applicants' proposed alternative)**	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
	(Note: the offshore footprint for operations is assumed to be based on the trestle/berth design for Nikiski and the length of trestle to get to 60-foot water depth; dredging to maintain that water depth for that length trestle cannot be estimated at this time.)	(permanent impact) **Offshore:** approx. 1,350 acres for construction (1,200 is estimated dredge disposal area) and 26 acres for operations (permanent impact)	(permanent impact) **Note:** an anadromous stream would either be permanently filled in or need to be re-routed out of the site. **Offshore:** approx. 1,000 acres for construction and more than 200 acres for operations (permanent impact)	acres (permanent impact) **Note:** a stream would either be permanently filled in or need to be rerouted out of the site. **Offshore:** approx. 2,000 acres for construction (1,600 for dredge disposal) and 26 acres for operations (permanent impact) plus the required maintenance dredging and disposal	acres (permanent impact) **Offshore:** approx. 2,700 acres for construction (2,400 is estimated for dredge disposal area) and 26 acres for operations (permanent impact) plus the required maintenance dredging and disposal	acres (permanent impact) **Offshore:** approx. 2,700 acres for construction (2,400 is estimated for dredge disposal area) and 26 acres for operations (permanent impact) plus the required maintenance dredging and disposal	acres plus 170 acres of waterbodies filled in for a total of 275 acres (permanent impact) An unknown number of wetland acreage would be impacted from development of mineral sites necessary to provide fill for the site. **Offshore:** approx. 2,000 acres for construction (1,600 for dredge disposal) and 26 acres for operations (permanent impact) plus the required maintenance	acres (permanent impact) An unknown number of wetland acreage would be impacted from development of mineral sites necessary to provide up to 13 million cubic yards of fill for the site. **Note:** two streams would either be permanently filled in or need to be rerouted out of the site. **Offshore:** approx. 1,350 acres for construction (1,200 is estimated dredge	acres (permanent impact) An unknown number of wetland acreage would be impacted from development of mineral sites necessary to provide up to 20 million cubic yards of fill for the site. **Note:** multiple streams would either be permanently filled in or need to be rerouted out of the site. **Offshore:** approx. 700 acres for construction (400 is estimated dredge

TABLE 10.3.2-5

Summary of Site Comparisons

Category	Criteria	Nikiski (Applicants' proposed alternative)	Anderson Bay	Cape Starichkof	Kasilof South	Ninilchik South	North Foreland	Robe Lake	Seward
							dredging and disposal	disposal area) and 26 acres for operations (permanent impact)	disposal area) and 26 acres for operations (permanent impact)
	Site Preparation constraints (relative amount of grading, blasting, demolition of structures, and disposal of rock and buildings)	Removal of structures and disposal of material required No bluff removal or slope grading required, or bluff stabilization	Extensive blasting and leveling/benching of the site required to build facilities Site rises to 2,500 feet from sea level More than 39 million cubic yards would need to be removed and disposed of in Prince William Sound.	Need to fill in stream or reroute it, remove some structures, and dispose of the materials Extensive bluff stabilization required to protect facility	Few structures to remove and dispose of; no bluff removal or stabilization required	Few structures to remove and dispose of; no bluff removal or stabilization required	More than five ponds and low areas would need to be filled in, requiring import of large amounts of suitable fill material. Would need to grade down bluffs and stabilize to access site	Streams would need to be filled in or rerouted around site Ridge on site would need to be leveled and/or material disposed of	Streams would need to be filled in or rerouted around the site.
Facility Operations	Need for operations camp (with associated additional footprint) to house workers, versus ability for workers to reside in nearby communities	None; operations staff can find housing in nearby communities.	Operations staff can find housing in Valdez with a 20-minute commute and bypass around the existing Valdez Marine Terminal.	Remote; operations camp would be required	None; operations staff can find housing in nearby communities.	None; operations staff can find housing in nearby communities.	Although the Village of Old Tyonek is less than 2 miles away, it is quite small and has inadequate housing. An operations camp would be required.	None; operations staff can find housing in nearby communities.	Remote; operations camp would be required

TABLE 10.3.2-5

Summary of Site Comparisons

Category	Criteria	Nikiski (Applicants' proposed alternative)	Anderson Bay	Cape Starichkof	Kasilof South	Ninilchik South	North Foreland	Robe Lake	Seward
Land Use	Conflicts with land use planning	None identified; in designated industrial area with mixed zoning	Not zoned for industrial uses; undeveloped state land; surrounded by National Forest Existing recreational land and water uses	Not zoned for industrial use	None identified	Undeveloped area; no zoning issues identified	Undeveloped area; no zoning issues identified	None identified	Resurrection Bay is designated a recreation area. Marine terminal zoning is not consistent
	Impacts to public lands that trigger ANILCA or additional regulatory processes	None identified for site or pipeline	None identified for site, but pipeline would cross National Forest land and Wild and Scenic rivers.	None identified for site or pipeline	None identified for site or pipeline	None identified for site although Native allotments are adjacent. None on pipeline.	Native allotments on and adjacent to site None identified for pipeline	Pipeline crosses National Forest and Wild and Scenic Rivers, though none identified for the site	None identified for site Pipeline impacts National Forest, wilderness areas, and Native allotments
Facility Permitting	Wetland and air permitting National Historic Preservation Act (NHPA) consultation	Adjacent Tesoro refinery requires site layout considerations to avoid cumulative air emission impacts One cultural resource site found on property; under SHPO evaluation	Adjacent Valdez oil terminal impacts cumulative air emissions from site; air permitting would require offsets Relocation or fill of anadromous stream is difficult to permit. Proximity to complex terrain	Site is within 63 miles of Class I airshed; additional modeling and potentially controls required No adjacent major air emission sources Extensive wetland fill and	Site is within 63 miles of Class I airshed; additional modeling and potentially controls required No major adjacent major air emissions sources.	Site is within 63 miles of Class I airshed; additional modeling and potentially controls required No adjacent major air emission sources.	Site is within 63 miles of Class I airshed; additional modeling and potentially controls required No adjacent major air emission sources	Valdez oil terminal far enough away not to impact air permitting No other major air emission sources nearby Wetland fill and multiple anadromous stream	No major air emission sources nearby Within 63 miles of Class I airshed; additional modeling and potentially controls required

TABLE 10.3.2-5

Summary of Site Comparisons

Category	**Criteria**	**Nikiski (Applicants' proposed alternative)**	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
			would likely make successful demonstrations of air quality compliance challenging	stream fill/relocation is difficult to permit.	Extensive wetland impacts are difficult to permit.	Wetland impacts are difficult to permit.	Extensive wetland fill and stream fill/relocation is difficult to permit. Five cultural resource sites are present on the property.	fill/relocation are difficult to permit Proximity to complex terrain would likely make successful demonstra-tions of air quality compliance challenging	Extensive wetland fill and anadromous stream fill/relocation is difficult to permit.
Protected Species	ESA- or state-designated CH and listed species jeopardy impacts from construction or operations impacts	Marine Terminal would be in Beluga whale CHA 2. Presence of Cook Inlet beluga whales would result in conditions for protection during construction of the facility.	None identified	Cook Inlet beluga whales present, resulting in conditions for protection during construction of the Marine Terminal	Marine Terminal would be in Beluga whale CHA 2 Presence of Cook Inlet beluga whales would result in conditions for protection during construction of the facility	Cook Inlet beluga whales present, resulting in conditions for protection during construction of the Marine Terminal	Marine Terminal would be in Beluga whale CHA 2 Presence of Cook Inlet beluga whales would result in conditions for protection during construction of the facility	None identified	None identified
Geological Hazards	Fault lines (within 5 miles)	None within 5 miles	Jack Bay fault	None within 5 miles	None within 5 miles	None within 5 miles	Bruin Bay fault on site	None within 5 miles	None within 5 miles.
	Volcanos	More than 50 miles from nearest volcano	More than 75 miles from active volcanos	More than 50 miles from nearest volcano	More than 50 miles from nearest volcano	More than 50 miles from nearest volcano	More than 50 miles from nearest volcano	More than 75 miles from active volcanos	More than 75 miles from active volcanos

TABLE 10.3.2-5

Summary of Site Comparisons

Category	Criteria	Nikiski (Applicants' proposed alternative)	Anderson Bay	Cape Starichkof	Kasilof South	Ninilchik South	North Foreland	Robe Lake	Seward
		Outside of any lava flow areas Ash deposition possible	Not in any ash deposition areas or lava flows	Outside of any lava flow areas Ash deposition possible	Outside of any lava flow areas Ash deposition possible	Outside of any lava flow areas Ash deposition possible	Outside of any lava flow areas Ash deposition possible	Not in any ash deposition areas or lava flows	Not in any ash deposition areas or lava flows
	Landslide potential	None	High with steep slopes (rises to 2,500 feet from shore over site) Would require additional measures to prevent impacts to site	None	None	None	None	None	Moderate with steep mountain slope behind site
	Tsunamis	Bluffs provide natural defense Small waves produced at site for 1964 earthquake	Steep grade at site allows site benches to be built above 22-foot wave height observed in 1964 earthquake	Bluffs provide natural defense 9–14-foot waves produced at site for 1964 earthquake	Bluffs provide natural defense Small waves produced at site for 1964 earthquake	Bluffs provide natural defense Small waves produced at site for 1964 earthquake	Bluffs provide natural defense Small waves produced at site for 1964 earthquake	Shallow gradient from shore to site (about 1 mile inland) with observed 22-foot wave height during 1964 earthquake Would require site to be built above this height or have protection	Some elevation provides protection for small waves 26.25-foot waves measured in this area during 1964 earthquake would require site to be elevated or protected

TABLE 10.3.2-5

Summary of Site Comparisons

Category	**Criteria**	**Nikiski (Applicants' proposed alternative)**	**Anderson Bay**	**Cape Starichkof**	**Kasilof South**	**Ninilchik South**	**North Foreland**	**Robe Lake**	**Seward**
Vessel Conflicts **NOTE:** does not include personal watercraft (only vessels tracked by the USCG)	Existing vessel traffic	More than 480 deep water vessels and more than 1,000 smaller vessels used/transited Cook Inlet in 2010.	More than 730 large and small vessels used/transited Prince William Sound into Valdez.	More than 480 deep-water vessels and more than 1,000 smaller vessels used/transited Cook Inlet in 2010.	More than 480 deep-water vessels and more than 1,000 smaller vessels used transited Cook Inlet in 2010.	More than 480 deep-water vessels and more than 1,000 smaller vessels used /transited Cook Inlet in 2010.	More than 480 deep-water vessels and more than 1,000 smaller vessels used/ transited Cook Inlet in 2010.	More than 730 large and small vessels used/ transited Prince William Sound into Valdez.	More than 230 large and small vessels used or transited Resurrection Bay (mostly in the summer).
	Width of waterway to accommodate LNGCs	More than 10 miles wide between the forelands (south of the site) No potential vessel traffic conflict with LNGCs	Valdez Narrows is less than 1 mile wide, together with LNGC safety zones and the control points of Hinchinbrook Entrance and Valdez Narrows could result in delays to LNGCs or Port of Valdez traffic	More than 90 miles wide No potential vessel traffic conflict with LNGCs	More than 90 miles wide No potential vessel traffic conflict with LNGCs	More than 90 miles wide No potential vessel traffic conflict with LNGCs	More than 10 miles wide (between the forelands, south of the site) No potential vessel traffic conflict with LNGCs	Valdez Narrows is less than 1 mile wide, together with the control points of Hinchenbrook Entrance and Valdez Narrows could result in controls that delay LNGCs or Port of Valdez traffic	Approx. 5 miles wide at its narrowest point south of the site Possible traffic control and delays with LNGCs' safety zones while in transit

10.3.2.4.1.1 Anderson Bay

The Anderson Bay site lies within the city limits of Valdez, an incorporated city connected via road to Interior Alaska. The Anderson Bay location is situated on undeveloped lands owned by the State of Alaska and managed by ADNR. The oil and gas sector is the largest private employer in Valdez. Anderson Bay has been the proposed location for an LNG liquefaction facility in previous, but now inactive, filings with FERC and other agencies.[15]

This site was not further considered in the alternatives analysis because of: 1) the prohibitive costs to develop the site, 2) the risks of constraints during operations in the Valdez Narrows, 3) the schedule risk of permitting a pipeline through two Wild and Scenic Rivers, 4) the technical/logistical impracticalities of laying a 42-inch pipeline through the steep grade of Thompson Pass and the narrow work areas of Keystone Canyon, 5) permitting issues associated with traversing the Chugach National Forest, 6) significant challenges associated with air permitting, and 7) additional impacts to wetlands and an anadromous fish stream. Each of these points is elaborated as follows.

1. The site lies to the south side of Anderson Bay and from shore, rises to an elevation of 2,500 feet. To use the site, benching, or terracing, of the land would be required to prepare level surfaces for the installation of the Liquefaction Facility. To accomplish this, extensive earthworks including blasting would be required over the course of several years to prepare the level working surfaces. FERC (1995) estimated that site excavation quantities would be approximately 9.7 million cubic yards (3,018,000 cubic yards of overburden and 6,655,000 cubic yards of rock). Of that material, approximately 3.8 million cubic yards of excavated material (about 19 percent rock) is estimated not to be required for the site and would require disposal. However, during the feasibility study for this Project, it was estimated that approximately 39 million cubic yards of overburden and rock would be removed, with the rock placed in Prince William Sound to form the base for the construction of the Marine Terminal and material offloading facility (MOF) required for the site (approximately 1,000 acres, with more than 200 as permanent fill). In addition, there would be more than 60 acres of wetland lost in the development of the site, and the need to fill in or reroute an anadromous fish stream that is on the site. This represents a considerable cost ($2.75 billion in incremental costs, not including marine facilities) and larger permanent impact to aquatic resources than would occur at the Nikiski site.

2. The Valdez Narrows, less than 1 mile wide, would be restricted during LNGC transit after being loaded with LNG. A safety zone would be established around fully laden LNGCs through the USCG review process that would restrict other vessel traffic through the Narrows (BLM and U.S. Army Corps of Engineers [USACE], 1988; BLM, 2002; FERC, 1995). Conversely, if there would be traffic in the Narrows, LNGCs would be forced to wait until it is clear before transiting the Narrows. Hinchinbrook Entrance would have similar controls and constraints to LNG delivery. With the current level of vessel traffic into and out of Valdez, the time frame to load and get underway an LNGC (24–48 hours) and the number of LNGCs that would be visiting the Liquefaction Facility (one to three per day, depending on size), any delays to transit to/from the facility would undermine the delivery certainty that foreign markets expect.

[15] A Section 3 NGA Order was issued to Yukon Pacific Corporation in 1995. It was later relinquished at the request of FERC (date unknown). Yukon Pacific also applied for a BLM ROW Grant in 1984 that was issued in 1988 after the BLM and USACE issued a Final Environmental Impact Statement (FEIS) on the 36-inch-diameter pipeline in 1988.

3. Although the Trans-Alaska Gas System (TAGS) (and to some degree the Trans-Alaska Pipeline System [TAPS] route that is followed by TAGS) was studied in the 1988 Final Environmental Impact Statement (FEIS) produced by BLM and the USACE and deemed to be an environmentally acceptable alternative to a route to Cook Inlet, there have been changes to conservation designations along the Valdez delivery option route that have occurred since the TAGS FEIS. Two rivers, one crossed and one paralleled (the pipeline would need to be within and also cross this river), have since been designated as Wild and Scenic Rivers by the National Park Service (NPS). The Gulkana River, crossed by a Valdez delivery option, and the Delta River, paralleled by a Valdez delivery option, would have to be avoided or require NPS/Congressional/Presidential approval to cross. There are no feasible options to avoiding either river (note: even a trenchless or aerial crossing still requires an easement across the National Park designation, and the NPS is not authorized by Congress to issue an easement without Congressional and Presidential approval). Congressional and Presidential approval, a basic routing constraint for most pipeline projects, is an exclusion factor with the routing of the delivery option for the Anderson Bay facility site.

4. The pipeline would have to traverse terrain steeper than on the Nikiski delivery option routing. Through Thompson Pass, the pipeline would traverse more than 5.5 miles of steep slope areas (>15 percent grade) trying to follow the TAPS alignment and Richardson Highway. As shown in Figure 10.3.2-1, there are many locations where that additional space is unavailable, making this routing technically infeasible without creating a new ROW down the mountain pass.

   This is the only existing access corridor from Valdez to other areas of the state (BLM and USACE, 1988), which is already constrained with the placement of the Richardson Highway and TAPS. The study undertaken by the Applicant and TAPS to examine collocation and crossing designs indicates that the proposed pipeline would not be allowed to be sited within the TAPS ROW for long stretches of the route. With the constrained space in the existing corridor, major route deviations would be required to move the natural gas to Valdez. TAGS routing was conceptual at the completion of the FEIS, and a long list of requirements was required by the BLM and USACE before final approval of the route, including detailed plans on how the pipeline would be placed through these two space-constrained features. The field surveys and mapping of wetlands and other features is out of date and would need to be redone to develop a constructible and permittable route. A new route would need to be prepared, with the possibility of tunneling or benching large areas of rock to prepare a safe and level location to put the pipeline. The ADOT&PF has expressed past concerns about the potential impact of pipeline construction or operations should a landslide occur, closing this pinch point (BLM and USACE, 1988). Keystone Canyon is a 2.6-mile-long, deep gorge of the Lowe River that has the same constraints with workspace as well as landslide risk (BLM and USACE, 1988). A recent significant landslide was realized in 2014 in the Canyon. The landslide resulted in the closing of Richardson Highway, the only road into Valdez, for almost two weeks. The technical challenges to build a pipeline in a new corridor across these two features would add risk to the Project schedule and costs because of the need to find and build through a new area with steep terrain and unstable soils.

   Although a route to Valdez move the pipeline in closer proximity to Fairbanks, it would be more difficult to deliver natural gas to Anchorage and the Matanuska-Susitna Valley. In addition, the pipeline would need to either pass through or be routed very close to the Alyeska Pipeline Marine Terminal, which could add to proximity issues along with potential security concerns.

Figure 10.3.2-1 View of Thompson Pass

5. Besides the exclusion factor of crossing the Wild and Scenic Rivers (as discussed in #3), the pipeline route would also have to cross through a National Forest. This action would trigger additional approvals above the local National Forest managers to Washington, D.C. This would add considerable permitting uncertainty for the Anderson Bay site.

6. As part of the site selection process, air quality dispersion modeling was conducted to evaluate potential air quality compliance issues for the Liquefaction Facility at two alternate sites in the Valdez area. The focus of this modeling was to assess whether the physical characteristics of the alternate sites (topography, meteorology, proximity to existing emission sources) would be conducive to a successful demonstration of compliance with applicable ambient air quality standards and federal Prevention of Significant Deterioration (PSD) increment limits. With this limited objective, it was only necessary to determine whether peak predicted pollutant concentrations due to facility emissions would likely exceed these regulatory thresholds. Therefore, the modeling methodology used for these sites was less comprehensive than would be required for a full air quality impact assessment under NEPA, or to support preparation of a construction permit application. For example, these analyses necessarily made use of existing meteorological input data sets that the Alaska Department of Environmental Conservation (ADEC) may not consider representative of conditions at the alternate sites.

Specific sites for which modeling studies were conducted include Robe Lake at the eastern end of the Port of Valdez and a location adjacent to the existing Valdez Marine Terminal (VMT) along the southern Port shoreline. Anderson Bay was also considered, but was not modeled separately for reasons described in the following sections. The preliminary modeling for the Robe Lake and the VMT sites showed that their proximity to complex terrain, i.e., land elevations above facility stack heights, would make successful demonstrations of compliance very challenging. In both cases, the peak predicted values were well above the National Ambient Air Quality Standard for one-hour nitrogen dioxide (NO_2) concentrations. However, the nearest terrain features at the predicted heights of facility emission plumes are within only about 1641 feet south of the VMT stacks, as opposed to 1.43 miles from the Robe Lake site. Accordingly, a preliminary screening modeling analysis showed that maximum one-hour NO_2 impacts due to facility operations at the VMT location would be more than twice as high as those predicted for the Robe Lake site. These results were obtained without accounting for emissions from marine vessels serving the Liquefaction Facility. In addition, the emissions from substantial existing sources located near these sites were not explicitly included in the model simulations. These included the Petro Star Valdez refinery near Robe Lake and the Alyeska Pipeline Valdez Marine Terminal adjacent to the VMT site. Inclusion of these sources would have resulted in higher cumulative impacts, thus increasing the margin of predicted noncompliance.

A separate modeling analysis for the Anderson Bay site was not considered necessary, owing to the close similarity of its topographic setting to that of the VMT site (elevated terrain immediately south of the Facility). It was determined that the predicted serious compliance problems for the VMT site would be no less serious and no easier to resolve for the Anderson Bay location.

7. Filling the nearshore habitat to dispose of the almost 40 million cubic yards of material created to level the site for construction of the facility, filling or rerouting a stream that serves as spawning grounds for the anadromous chum (*Oncorhynchus keta*) and pink salmon (*O. gorbuscha*), along with filling more than 60 acres of wetlands on the site has greater environmental impacts than the Applicants' proposed alternative at Nikiski.

10.3.2.4.1.2 Cape Starichkof

Of the sites selected for further evaluation, the Cape Starichkof site is the southernmost site on the Kenai Peninsula. The site is undeveloped and located in an area near the southern terminus of the Sterling Highway, which ends in Homer. The general area has previously been identified as a potential prime industrial site, suggested due to the combination of large tracts of uplands suitable for industrial development, and beach access; however, it is also considered an important recreational area.

This site was discounted during the feasibility study because of the following exclusion factors: 1) The extensive amount of wetlands (40 percent) of the site that would be permanently filled with no suitable location nearby to minimize this amount of impact. There are also anadromous streams on the site that would need to be filled or rerouted that connect to Stariski Creek. 2) The 60-foot depth contour is almost 2.4 miles offshore. Either an uneconomically long trestle and cryogenic pipeline would be required, or dredging would be required for both construction and operations to use this site. Neither 1) nor 2) are favorable when compared to the Applicants' proposed alternative at Nikiski. These reasons are more fully explained in the following paragraphs.

1. Within the site and in the surrounding area are extensive low bog wetlands, interspersed with numerous streams and tributaries that connect to Cook Inlet. More than 330 acres of wetlands within the site would be permanently filled or impacted. There are no other suitable locations in this location that would avoid wetlands to the extent that wetlands are avoided at Nikiski (see Appendix B). The region is located between Cook Inlet and several rivers (Stariski Creek, Anchor River, Chakok River) with wetland features associated with those rivers that prevent avoidance of wetlands or waterbodies.

   The Cape Starichkof site itself encompasses portions of various tributaries to Stariski Creek, an anadromous fish stream. Stariski Creek and its tributaries serve as both spawning and rearing grounds for fish species including coho (*O. kisutch*), chinook (*O. tshawytscha*), and pink salmon. Also present are Dolly Varden char (*Salvelinus malma*) and Steelhead (*O. mykiss*) trout. These tributaries would need to be rerouted or filled in, permanently altering the use and quality of these for spawning and rearing grounds.

   Compared to the Applicants' proposed alternative, this site has considerably more impacts to wetlands and waterbodies.

2. Shallow water prevails off the coast, with numerous sand bars and potentially hard-bottom areas. To support construction, a MOF would be required at the shore, with a dredged area to support the unloading of modules and material for the construction of the facility at the site. This would require extensive dredging from shore out to about 2 miles to get to a water depth to support barges and module carriers to reach the site.

   In addition, the marine trestle would either be 2 miles long, substantially increasing cost over the Nikiski site, or 1 mile long or less, with extensive dredging required from the end of the berthing facilities out to the 60-foot depth contour. This would result in dredging a turning basin and navigation channel more than 1,000 feet wide for up to 2 miles. For the MOF and marine trestle dredging and disposal, another 2,000 acres of waters of the United States would be impacted.

   The combination of these two points, or either of them alone, shows that this site has considerably more impacts when compared to the Applicants' proposed alternative, Nikiski.

10.3.2.4.1.3 Kasilof South

The Kasilof South site is located south of the Kasilof River on the Kenai Peninsula, with access from Cohoe Loop Road. The majority of the Kasilof South site is undeveloped with woodland vegetation cover. The shoreline of Kasilof South site consists of privately owned homesteads, interspersed among Kenai lowland forests, and contains numerous setnet fishing leases, as well as tidal leases granted by ADNR.

The offshore area of the Kasilof South site is located within ESA Beluga Whale Critical Habitat Area (CHA) 2. The site's shoreline is also part of the Clam Gulch CHA near the northern origin of the CHA. Extending along the eastern shores of Cook Inlet from Cape Kasilof south to Happy Valley, the Clam Gulch CHA was established in 1976, providing public access to razor clam beds.

This site was eliminated during the feasibility study for the exclusion factor similar to number 2 discussed above for Cape Starichkof: it is almost 3.8 miles from shore out to the 60-foot depth contour. Together with the permanent loss of 88 acres of wetlands onshore, the extensive dredging and dredge disposal to make this site work in the shallow offshore environment would result in more than 2,700 acres of impacts to wetlands and waterbodies.

10.3.2.4.1.4 Ninilchik South

The Ninilchik South site is located on the Kenai Peninsula between Deep Creek to the north and the Ninilchik River to the south, encroaching on the heavily used Deep Creek State Recreation Area (SRA) managed by ADNR. Deep Creek and its tributaries serve as both spawning and rearing grounds for fish species, including coho, chinook, and pink salmon. Also present are Dolly Varden char and steelhead.

Located in a relatively undeveloped area and with a population of approximately 883 residents, the surrounding community is unaccustomed to large-scale industrial development. Commercial fishing, recreation, and tourism form the basis of the local economy, with the community’s lifestyle tied to the productive salmon habitats provided by Deep Creek and the Ninilchik River. In addition, the site is located along a portion of the Clam Gulch CHA. However, there are no shore fishery leases, tidal leases, tidal easements, tidal conveyances, or offshore permits or leases located along the shoreline of the site.

During the feasibility study, it was determined that this site could be eliminated for the same exclusion factor that was discussed for Cape Starichkof, which was the distance from shore to water depths adequate to support LNGC loading. It is 3.7 miles from shore to the 60-foot depth contour, and this would equate to more than 2,700 acres of dredge and dredge disposal impact to wetlands and waterbodies. Together with the 112 acres of wetlands that would be filled in developing the site, this site has considerably more impacts than the Applicants’ proposed Nikiski alternative.

10.3.2.4.1.5 North Foreland

The North Foreland site is located within Beshta Bay on the western side of Cook Inlet and consists entirely of Tyonek Native Corporation lands. The site is largely undeveloped, except for several oil and gas wells, well pads, and timber roads, and is fronted on three sides by sensitive land uses: Trading Bay State Game Refuge (SGR) to the west and southwest; Tyonek Village and subsistence use of Alaska Native Claims Settlement Act lands located to the immediate northeast; and ESA Beluga Whale CHA 2 in the surrounding waters of Upper Cook Inlet.

The nearby community of Tyonek is a traditional Native Village, with residents conducting subsistence use activities. Residents hunt, fish, trap, and gather plants and berries on the Trading Bay SGR, Native allotments, and areas near the North Foreland site.

This site was eliminated during the feasibility study for the following exclusion factors: 1) It is 2.2 miles to the 60-foot depth contour. As stated for the previous three sites, this results in considerable impacts for both construction and operation to the marine habitats of Cook Inlet. 2) There are approximately 275 acres of onshore wetlands and waterbodies (five ponds), as well as two tributaries that would have to be filled in, one a tributary to Tyonek Creek, an anadromous fish spawning and rearing habitat. Considerable fill would be required to fill the wetlands and ponds and level the site for building the Liquefaction Facility. This material would need to be excavated from nearby material sources that would have to be created for the Project (there are no existing permitted sources nearby), increasing the Project footprint that would impact wetlands either from the mineral source or the roads to/from the mineral sources. There is little to no infrastructure near the site. A road may need to be built to support construction and operation from the east, increasing Project footprint and wetland impacts. 3) There is a fault line that is partially found under the site. The impacts of this to the design of the facility and any additional strengthening or reinforcement is not known, but would be far more expensive than any of the other sites without any faults on site. 4) There are five known cultural resource sites on the North Forelands alternative site. The Project has a standing siting criteria to avoid, to the extent practicable, known cultural resource sites. Each of these exclusion factors is discussed in the following paragraphs.

1. For reasons discussed for the previous three sites, the extensive amount of dredging and dredge disposal is higher than for the Applicant's proposed alternative site (Nikiski). It is over 2 miles to the 60-foot depth contour. This would require dredging more than 1.9 million cubic yards of material that would impact about 2,000 acres of Cook Inlet marine habitat, near to where belugas are known to congregate to feed on migrating salmon that travel along this coastline.

2. The site is a low area with wetlands, ponds, and streams that would all be filled in, or in the case of one stream, rerouted. This would impact more than 275 acres of known onshore wetlands. One of the streams is a tributary to Tyonek Creek, an anadromous spawning and rearing habitat for pink and silver salmon. An additional unknown number of wetland acreage would be impacted to develop material sources nearby, roads to those sources, and a major road from the east to support the facility during construction and operation. It is not unreasonable to expect that hundreds of other acres of wetland and waterbodies would be impacted, including Tyonek Creek, to develop this location.

3. The Bruin Bay fault would need to be studied with extensive geophysical and geotechnical investigations to determine the potential level of activity and the required mitigation measures necessary to ensure the safe operation of a Liquefaction Facility on the site. A basic siting criteria to avoid as the risks associated with siting a Liquefaction Facility on this location would considerably increase the costs of development, if it were found to be feasible to place a facility at this location.

4. Although the known sites have not been studied to determine their eligibility for listing on the NRHP, there would be delays assessing and mitigating any of the five sites that are deemed eligible. More importantly, the presence of the five sites indicates that additional cultural properties are likely to be found when the required surveys of the site, mineral sites, roads, and any other infrastructure footprint are surveyed. With their proximity to the Tyonek Village and the potential historical significance of these sites to the tribe's heritage, additional permitting work would be required to properly document, process, review, and gain concurrence before any site work could proceed. As stated previously, it has been the Project's objective to avoid disturbing cultural resources to the extent practicable.

Together with the additional impacts to wetlands and waterbodies, the impacts to cultural resources under Section 106 of the National Historic Preservation Act (NHPA) are more extensive than those for the Applicants' proposed alternative (Nikiski).

Although the pipeline route would be shorter to the North Forelands site, the impacts to Cook Inlet from laying a pipeline on the bottom of the seabed would be temporary and consistent with the permitting of the numerous pipelines throughout Cook Inlet. The additional impacts to onsite wetlands and waterbodies and Cook Inlet operational dredging outlined previously far exceed those of the Applicants' proposed alternative, even considering the temporary impacts of laying a pipeline across Cook Inlet. The impacts outlined are permanent, and would take place in a relatively undeveloped area that is heavily used for subsidence activities by the Tyonek tribe.

10.3.2.4.1.6 Robe Lake

The Robe Lake site lies near the head of Valdez Arm, a natural fjord that reaches inland for approximately 11 miles from Prince William Sound. The site is located within the city limits of Valdez, approximately 3 miles east of Port Valdez, the northernmost ice-free port in the United States. The area is surrounded by the Chugach Mountains, which are heavily glaciated mountains. Unlike the site at Nikiski, the Richardson Highway is between the site and the water. Moving the highway to avoid operational conflicts with the cryogenic pipeline and marine trestle would create far greater impacts than the Kenai Spur Highway relocation near the Nikiski site. The topography surrounding this area would require a larger highway footprint and more earthwork to create a level and safe pathway for the highway than would relocating the Kenai Spur Highway a few miles to the east through level terrain.

The Robe Lake site is located near the confluence of several anadromous streams and tributaries to both the Robe River and Robe Lake. The anadromous streams present on the site serve as spawning and rearing grounds for several fish species including coho, sockeye (*O. nerka*), chum, and pink salmon, as well as Dolly Varden char. An occasional chinook salmon is also found in these waters.

The Robe Lake site is generally forested to the north and east. Land cover on the western and southern fringe of the site consists of developed lands and residential areas including the Robe Lake, Northern Lights, and Corbin Creek subdivisions. The site also encroaches on several winter and summer trails used primarily by residents for snowshoeing, skiing, snowmachining, and general recreation.

The site is located within a planning area (Area G: Glacier Stream to Allison Creek) included as part of the Valdez Waterfront Development Plan (Sorum and Kinney, 2007). Planning priorities established under the waterfront development plan include preservation of fish habitat, including spawning sites and fishing areas; promotion of recreation-related development and opportunities; and future development of a Petro Star Refinery fuel loading dock.

This site was dismissed during the feasibility study because of the following exclusion factors: 1) The risks of constraints during operations in the Valdez Narrows, 2) the technical/logistical impracticalities of laying a 42-inch pipeline through the steep grade of Thompson Pass and the narrow work areas of Keystone Canyon, 3) the schedule risk of permitting a pipeline through Wild and Scenic Rivers and the National Forest, filling or relocating two anadromous fish streams, and the 64 acres of onsite wetlands, 4) significant air quality permitting issues, and 5) the requirement to either build the entire site above potential tsunami wave height (during the 1964 earthquake, a 21-foot wave went through this area) or building a protective barrier around the site. This would include the marine trestle and cryogenic pipeline; both pipelines would be over 1 mile long from the site to the 60-foot depth contour. The impacts and costs to acquire the required fill material, as well as the reinforced marine trestle design, would make this alternative considerably more expensive than the Applicants' proposed alternative. Points one through three are discussed in the previous Anderson Bay section.

Finally, the 1964 earthquake generated a tsunami of over 20 feet in this part of Prince William Sound. It destroyed the docks at Valdez. Current design code would require a facility at this location to either elevate and reinforce any marine facilities to accommodate another tsunami of similar size or to relocate the site. The Marine Terminal would consist of a trestle and cryogenic pipeline over 1 mile in length, therefore, considerable reinforcement would be required, even if the Marine Terminal would be elevated above the 20-foot tsunami height to withstand the force of the wave energy. The facility itself would also have to be built an additional 3 to 5 feet above the trestle height. This would require approximately 4 to 13 million cubic yards of material to raise the elevation of the site. A large footprint of mineral sites would be created and disturb far more than the site itself.

The logistical and technical challenges for designing and building a facility at this site would create considerable schedule and cost risks for the Project. Together with the fact that the impacts to wetlands and waterbodies are more than from the Applicants' proposed alternative, this site was rejected from further consideration.

10.3.2.4.1.7 Seward

Seward is located on the eastern Kenai Peninsula near the head of Resurrection Bay. Seward has historically served as a transportation center with rail access to Anchorage and Interior Alaska, overland transportation via the Seward Highway, and direct marine access to Prince William Sound and the Gulf of Alaska. The city also serves as the southern terminus for the Alaska Railroad Corporation (ARRC).

The Seward site considered for placement of the Liquefaction Facility is located on the eastern side of Resurrection Bay, across the bay from the populated portion of Seward and Seward Harbor. The site is developed with little forested cover and includes the Seward Marine Industrial Center (SMIC), a state correctional facility, and additional areas slated for development. The Project is generally consistent with the economic development and industrial land use goals stated in the SMIC Development Plan (Seward Harbormaster and Community Development Department, 2008) and City of Seward 2020 Comprehensive Plan (Seward Planning and Zoning Commission, 2005), although the SMIC plan calls for multiple-use and occupation of the industrial center.

The mouths of the Resurrection River and Fourth of July Creek are located south of the Seward site, with a portion of Fourth of July Creek being within the site boundary. There are three anadromous streams or potential spawning areas identified on the site, including Fourth of July Creek and Spring Creek. These streams serve as spawning and feeding areas for coho, chum, and pink salmon. The City of Seward also possesses one tidal conveyance within the site boundary.

A pipeline that could deliver natural gas from the GTP to the Seward site would diverge from the other delivery route options north of Anchorage and traverse down the east side of Anchorage, crossing the Chugach National Forest. The pipeline would be longer, by approximately 70 miles, than the other delivery route options (impacting more land [over 20 acres per mile more] and requiring additional compression).

This alternative was dismissed during the feasibility study because of the following exclusion factors: 1) The technical and logistical impracticality of moving a state prison, 2) the logistical impracticality of finding the necessary mineral sources to build the site up to 25 feet to withstand future tsunami events, and 3) the schedule risk of permitting a pipeline through a National Forest and filling or relocating two anadromous fish streams and tributaries to them, in addition to permanent wetland fill. These three flaws are elaborated upon as follows:

1. As previously outlined, the Seward site would encompass the existing SMIC and a state prison. Both would require relocation from the site and their structures would need to be demolished and materials disposed of. The Project would have to fund the building of a new state prison, once

suitable land had been identified by the state. The time to accomplish these steps would not meet the Project's intended schedule to meet market demand. The location chosen is well away from populated centers and nothing similar exists in this area of Seward.

2. Similar to the issues with Robe Lake site, this location experienced a tsunami of 24 feet during the 1964 earthquake. The site would need to be considerably built up to withstand a similar event before FERC would approve of the location. Ten to 15 or more feet would be required across the entire site, driving the need for more than 12 to 20 million cubic yards of minerals to build up the site. Because of the topography of the surrounding area, most of this material would need to be excavated elsewhere and shipped to the site. This would increase the costs of site development considerably and lead to greater impacts in the mining and site development than for the Applicants' proposed alternative both in the new larger footprint for mineral site development and the disposal of the existing buildings after demolition.

3. Similar to the issues with the Anderson Bay site, the pipeline to the Seward site would need to traverse long stretches through the Chugach National Forest. This action would trigger additional approvals beyond the local National Forest managers to those in Washington, D.C. The use of the Seward site would also require filling more than 110 acres of wetlands permanently on the site, in addition to the filling or relocating two anadromous streams and their tributaries. Additional wetland and waterbody impacts would occur where mineral sources are mined to provide the necessary fill at the site. The crossing of the National Forest and the fact that the impacts to wetlands and waterbodies are more than the Applicants' proposed alternative make this site less attractive for siting.

10.3.2.5 Liquefaction Facility Siting Conclusions

Following the feasibility analysis, the Nikiski site was chosen as the Applicants' proposed alternative. Following is a summary description of the site and the rationale for selection of the Nikiski site as the Applicants' proposed alternative.

The Nikiski site is on Alaska's Kenai Peninsula, approximately 7.6 miles northwest of the city of Kenai, which has a population of approximately 4,500 residents. The Nikiski location contains a portion of the Nikiski Industrial Area, which includes four major petrochemical processing facilities, and is one of the largest existing industrial complexes in Alaska. Currently, there are three marine facilities[16] near Port Nikiski and infrastructure in place to support industrial facilities. The presence of all of these adjacent facilities provides historical information and records that help in the planning and development of a new export terminal. While there is active shipping activity in this vicinity, potential conflicts are not anticipated.

The oil and gas industry has studied the Cook Inlet area onshore and offshore environment for decades and has safely built and operated facilities there to support oil and gas production, as well as feedstock for petrochemical facilities.

Unlike the other sites, the location would not require additional fill to build up the site, extensive blasting/excavation to use the site (unlike Anderson Bay, North Forelands, Robe Lake, Seward), or

[16] Several agencies had recommended that one of the existing marine terminal facilities could be used for the Project. This is addressed under Marine Terminal Alternatives (10.3.3.2).

extensive dredging to use the site (unlike Cape Starichkof, Kasilof, North Forelands, Ninilchik South). It would have the fewest impacts to waters of the United States on the site (only 16 acres of wetlands) and only temporary impacts to Cook Inlet marine habitat for dredging (Nikiski only has dredging for the period of construction). From a marine traffic and vessel conflict standpoint, only the sites in Cook Inlet have an acceptable level of risk associated with using the waterway (unlike Anderson Bay, Robe Lake, and Seward).

The pipeline delivery option to Nikiski would not impact Wild and Scenic Rivers (unlike Anderson Bay and Robe Lake) or require technically and logistically challenging pipeline designs that would be impracticable from a cost and schedule standpoint (unlike Anderson Bay, Robe Lake, and Seward). In addition, a pipeline route to Nikiski would better support the Project objective to provide natural gas for in-state deliveries by striking a balance for access to the Anchorage/Matanuska-Susitna Valley and Fairbanks areas, whereas a route to Valdez would readily serve Fairbanks, but require a lengthy lateral to Anchorage and the Matanuska-Susitna Valley.

Technical and logistical impracticalities are also avoided at the Nikiski site by not having to design for long trestles and cryogenic pipelines (unlike Robe Lake, Cape Starichkof, Kasilof, North Forelands, and Ninilchik South) or through steep-grade terrain with workspace limitations (unlike Anderson Bay and Robe Lake). Together with the fact that the Nikiski site has the fewest impacts to wetlands and waterbodies, the technical, logistical, and cost implications to make the other sites suitable for use clearly show that the Nikiski site is the best alternative.

The Marine Terminal and the Mainline pipeline for the Nikiski site would be constructed and operated in CHA 2 for the endangered Cook Inlet beluga whale. Consultation with the National Marine Fisheries Service (NMFS) has been initiated and will continue to identify measures needed to reduce impacts to this species. See Resource Report No. 3 for additional discussion on impacts and mitigation.

Facilities within Nikiski that support an existing marine terminal include the Agrium Facility directly north of the preferred site, and the Kenai LNG Plant (see Section 10.3.1.1.1). The Agrium Facility is currently out of service and has not been operational since 2007. The existing Kenai LNG Plant, north of the Agrium Facility, maintains an active marine terminal sized for smaller volume LNG carriers (87,500 cubic meters to 138,000 cubic meters). These existing facilities were not deemed to be feasible alternatives over the Proposed site. Issues identified with potential use of the Agrium facility include:

- The site (100 acres) does not provide the required acreage required for the Project and none of the current infrastructure (including the loading jetty) is salvageable for LNG service;
- The site could not satisfy the exclusions zones required around the Project facilities without impacting neighboring facilities;
- The facility is not owned by the applicant and the owner of the facility is considering spending $250-300 million to restart operations, with the Alaskan government passing legislature to help materialize the effort;
- Use of the site would affect the Project's ability to comply with ADEC Alaska Ambient Air Quality Standards (AAAQS) guidelines at the northern boundary; and
- The site is on the State of Alaska's contaminated site list and has been under an ADEC environmental action plan since 2007.

Issues identified with potential use of the Kenai LNG facility include:

- The site (200 acres) does not provide the required acreage required for the Project and none of the current infrastructure is salvageable for LNG service;
- The site could not satisfy the exclusions zones required around the Project facilities without impacting neighboring facilities;
- The facility is not owned by the applicant; and
- Use of the site would affect the Project's ability to comply with ADEC AAAQS guidelines.

Additional details of the Kenai LNG facility are provided in Section 10.3.1.1.1.

In summary using either the Agrium or Kenai LNG facilities would not be feasible because the acreage of these facilities is too long and narrow, which would not meet safety buffer requirements (e.g., vapor cloud dispersion, noise, etc.) to stay within the lease boundaries and would not be feasible with internal facility siting spacing requirements.

10.3.3 Liquefaction Facility Layout Alternatives

10.3.3.1 LNG Plant

The configuration of the Liquefaction Facility is guided by the siting requirements of 49 C.F.R. 193, as well as other industry and engineering standards that dictate spacing of buildings and safety considerations for workers. Regulatory requirements stipulate that potential thermal exclusion and vapor dispersion zones be contained within the site boundaries; therefore, those requirements limit the locations of specific pieces of equipment for the Liquefaction Facility. Similarly, thermal radiation zones associated with flares require specific distances from other pieces of equipment and from property lines as well. Layout arrangements that could not meet preliminary estimated exclusion zone criteria were not considered further. The Applicant did not identify alternative configurations that would meet the regulations, codes, and guidelines and avoid or reduce impacts in comparison to those of the proposed LNG Plant configuration. In addition, there were no discernible environmental differences related to equipment layout across the site, except for air quality dispersion modeling as described in Section 10.3.3.3.1. Alternatives to the Marine Terminal layout are discussed in the following section.

10.3.3.2 Marine Terminal

As described in Section 1.3.1.2 of Resource Report No. 1, the Marine Terminal would be constructed adjoining the LNG Plant in Cook Inlet and would allow LNGCs to moor and load LNG. The marine facilities would be designed for two loading berths and would include:

- Product Loading Facility (PLF); and
- MOF.

The PLF would be a permanent facility for the duration of the LNG export operations. Additionally, a temporary MOF would be required to enable direct delivery of cargoes (construction bulk material, equipment, modules, etc.) to site.

The existing nearby facilities would require significant upgrades to meet current regulatory requirements, in order for these facilities to be used for LNG export. The Applicant is still evaluating potential use of these existing facilities for purposes of cargo delivery to minimize dredging and construction impacts without impeding ongoing use of the facilities.

10.3.3.2.1 Marine Terminal Siting Considerations

The proposed site is located south of four existing facilities. From north to south, these are the Rig Tenders dock and the Tesoro, Kenai LNG, and Agrium marine terminals. Rig Tenders is designed for barging of equipment, material, and small modules. Tesoro terminal is designed for tank vessels (for petroleum products and oil) and not configured for loading LNG. The Kenai LNG Plant is currently operational, sized, and fit-for-purpose to move the smaller volumes of LNG (LNGC sizes in the range of 87,500 cubic meters to 138,000 cubic meters) currently under contract at that facility. The Agrium facility, which is currently out of service and has not been operational since 2007, is designed for bulk carrier (for fertilizer and associated products) and not configured for exporting LNG.

A preliminary assessment of the neighboring facilities and their potential use for LNG export indicated that major upgrades, retrofit, and/or wholesale replacement would be required to accommodate the size of LNGCs planned (size will range from 125,000 cubic meters to 216,000 cubic meters) and to move the volume of LNG required for this Project. Because existing facilities are not technically suitable, they could not be used for operations of the Project and are therefore not a viable alternative.

The constraints that have influenced selection of the Applicants' proposed alternative for the Marine Terminal at the proposed site include:

- Marine operations and safety – The neighboring facilities' proximity poses constraints to Project operations, which influences the siting of the Marine Terminal as far south as possible from the existing facilities. The siting criteria include:
  - Marine safety for vessels arriving and departing neighboring berths and for LNGCs arriving and departing from the proposed Marine Terminal was an important consideration in selection of terminal alternatives; and
  - Ambient air quality impacts from the emissions of LNGCs in combination with the LNG Plant and neighboring facilities.
- Bathymetry – The farther south from the neighboring terminals, the shallower the water becomes along the shore. This requires a longer trestle to reach operational water depths (53 feet). The optimal location for the Project's Marine Terminal would balance the costs for the longer trestle against the increased safety risk of a longer trestle. A longer trestle length in Cook Inlet could impact existing vessel traffic patterns and/or impact vessel traffic entering and leaving the neighboring marine terminals.
- Sedimentation and dredging – Some sedimentation is anticipated in the nearshore area of the MOF, which is proposed to be dredged. Initial sedimentation modeling estimates that up to a maximum of approximately 3.6 feet of sediment could be deposited per year; however, this model would be refined with acquisition of site-specific data. The frequency and degree of maintenance dredging required would be evaluated for impacts to construction operations,

environmental impact, and cost. Significant sedimentation is not anticipated at the location of the proposed PLF.

The location of the Marine Terminal in relation to the neighboring terminals is balanced between achieving an economic trestle design to reach the 53-foot depth contour, while minimizing impacts to Cook Inlet and neighboring facility vessel traffic against the environmental impacts of trestle design/placement and amount of dredging required. A discussion of the alternatives considered for each of the components of the Marine Terminal is provided in the following sections.

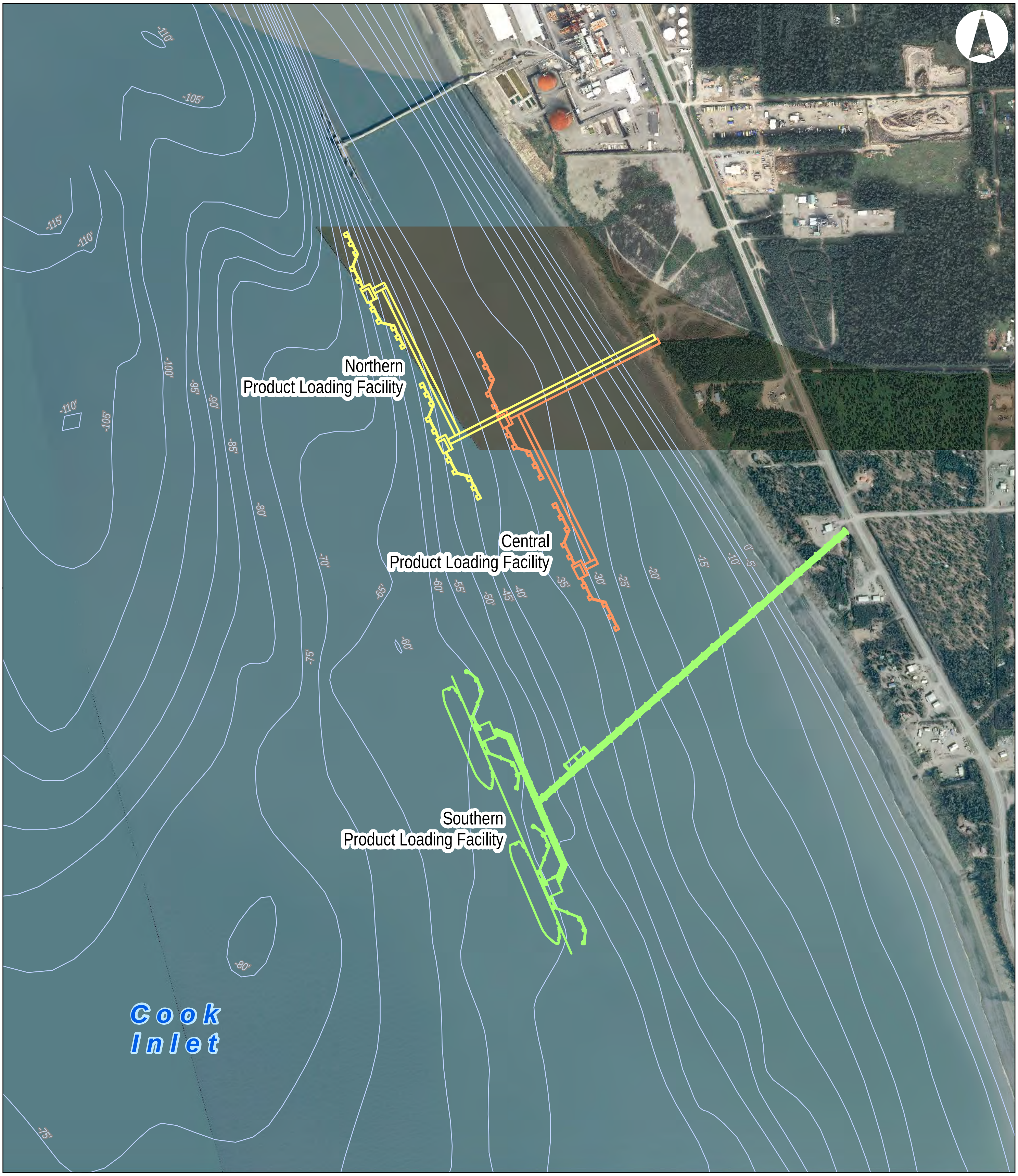
10.3.3.3 Product Loading Facility (PLF)

10.3.3.3.1 PLF Siting Alternatives

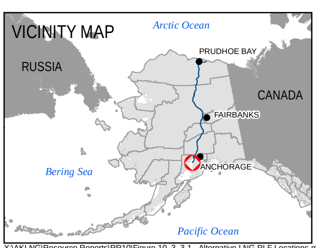
Within the Liquefaction Facility site, three areas were evaluated for placement of the PLF: northern, central, and southern alternative locations. An overview of these three alternatives is provided in Figure 10.3.3-1.

Each alternative location was evaluated primarily on four criteria:

- Avoiding or minimizing operational dredging associated with providing berths with a water depth of -53 foot Mean Lower Low Water (MLLW) water depth, including necessary under-keel clearance;
- Avoiding vessel-related conflicts due to the proximity of neighboring marine terminals with the Project's PLF. Vessels approaching the neighboring marine terminals north of the Liquefaction Facility would need to easily clear the ship loading safety zone on arrival and departure;
- Avoiding cumulative air emission impacts with neighboring facilities that can affect the Project's PSD permit; and
- Trestle length and associated construction costs.



VICINITY MAP



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LEGEND

- Product Loading Facility
- Product Loading Facility (North Option)
- Product Loading Facility (Central Option)
- Bathymetry Contour

0 500 1,000 2,000 Feet

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ALTERNATIVE LNG PLF LOCATIONS

FIGURE 10.3.3-1

ALASKA LNG

A comparison of the three PLF alternatives is provided in Table 10.3.3-1.

TABLE 10.3.3-1

Comparison of the Product Loading Facility (PLF) Layout Alternatives

Criteria			Alternatives: Southern Alternative (Applicants' proposed alternative)	Central Alternative	Northern Alternative
Engineering/Technical Considerations	Conflicts with neighboring Agrium Marine Terminal if Agrium restarts the facility		No	No	Yes
	Offshore Trestle Length (feet) (longer = higher cost)		3,500	1,680	2,300
Environmental	Seafloor Disturbance to Support Operations	Estimated Need for Dredging[a] (cubic yards)	0	3,000,000	0
		Estimated Need for Maintenance Dredging (cubic yards per year)	0	1,000,000	0
	Impact to setnet fishing leases due to safety zones during operations[b]		no leases (0 acres)	Five leases (50.33 acres)	Two leases (27.32 acres)

[a] Assume one-time

[b] Based on a nominal 1,640-foot radius around the berths

The southern alternative, the Applicants' proposed alternative, requires the longest offshore trestle due to shallower water closer to shore at the southern end of the Nikiski site; however, there is no dredging proposed for operations for this trestle length. The central alternative would require dredging because the trestle length cannot be extended or there would be vessel maneuvering conflicts with the neighboring marine terminals. The Agrium facility is currently not in service, but has applied to ADEC for restart of operations. Use of the northern alternative would only be a viable alternative if that facility remained out of operation. The southern alternative presents the least potential for vessel operation conflicts with neighboring marine terminals and environmental impact. Furthermore, emissions from the southern alternative would not result in cumulative air emission impacts with the neighboring facilities. Thus, the southern PLF location is the Applicants' proposed alternative.

10.3.3.4 Temporary Material Offloading Facility (MOF)

10.3.3.4.1 MOF Layout Alternatives

To minimize the time required for construction, reduce overground traffic, and improve safety, a temporary MOF would be required in the Nikiski area. Constructing the temporary MOF immediately adjacent to the construction site would allow delivery of large modules directly to the construction site and reduces impacts to local residents. A MOF would need to:

- Accommodate offloading of Project-related construction bulk materials, equipment, and modules. This includes accommodating three different types of vessels: Oceangoing barges for offloading floating or grounded cargo, heavy lift vessels (Lift-On/Lift-Off [Lo-Lo]) that use the ships' cranes to offload cargo, and heavy transport ships (Roll-On/Roll-Off [Ro-Ro]) that offload using self-propelled module transporters (SPMTs).

- Serves as a central location for the marine contractors' fleet of vessels.

- Accommodate daily access in a variety of tidal ranges and wave conditions.

- Have a design life of at least 10 years with the ability to withstand ice abrasion, freeze, thaw, currents, corrosion, and natural disasters (e.g., earthquakes and tsunamis).

A low-incline heavy haul road from the offloading site traversing the bluff to the LNG Plant area would also be required to enable transport of equipment and materials to the construction site.

10.3.3.4.2 Onsite MOF Configurations

On the shoreline of the proposed Nikiski Liquefaction Facility site, three alternative MOF options were evaluated:

- Nearshore MOF where barges would be grounded to the seafloor to offload them;

- Nearshore MOF that has a dredged channel and allows vessels to stay floating while they are offloaded; and

- Offshore MOF (away from the shoreline) that would require minimal dredging to allow vessels to moor to the MOF while unloading.

The analysis shown here is only applicable to the Applicants' proposed PLF alternative. Any other PLF alternative would require a different configuration of MOF alternatives. For instance, the grounded barge option would not be feasible for the northern PLF alternative because the MOF would be south of the PLF in shallower water, requiring dredging. Therefore, the selection of the PLF was completed first, resulting in the alternatives evaluated in the following table for the MOF.

The berths for the alternative nearshore MOF with floating vessel offloading would be located as near to the shore as practically possible and require dredging to obtain the required water depth of -32 feet MLLW to enable the largest vessels to remain afloat through all stages of the tide. The berths would typically be aligned with the current to minimize the mooring loads. A floating pontoon would also assist Ro-Ro module offload operations to the north of the MOF.

The quay for the alternative nearshore MOF with grounded barges would have the ability to accommodate up to three 400-foot grounded barges at any time. The elevation of the grounded barge bed would be approximately +0 feet MLLW and the top of the quay at +30 feet MLLW. A traditional sheet-pile wall solution is assumed with select backfill and a durable surface such as asphalt. Behind the quay, a laydown area is available as a staging area for modules before they are transported up the MOF haul road to the plant construction area.

The berths for the alternative offshore MOF would be located farther offshore to reduce the dredging requirement. The facility would be designed to accommodate deep-draft Ro-Ro and Lo-Lo vessels, which always remain afloat during cargo discharge. The MOF quay would be connected to the shore via a solid rubble-mound causeway with a laydown area at the shore to allow staging of the modules prior to moving up the haul road to the onshore plant.

Each MOF option was evaluated based on the following criteria: footprint of seafloor disturbance, dredging requirements (one time or maintenance), impacts to LNG Plant construction, construction or operation feasibility of the MOF, and cost. Although the nearshore MOF that allows vessels to stay floating while they are offloaded requires dredging, it was selected as the Applicants' proposed alternative because it:

- Does not require a solid rubble-mound causeway like the offshore MOF alternative along with its related seafloor footprint and potential effects on fish and marine mammal movements along the shoreline;
- Has no or limited operations constraints for vessels at berth as compared to the nearshore MOF alternative with grounded barge offloads; and
- Has lowest cost of cargo delivery and provides higher schedule certainty than the nearshore MOF alternative with grounded barge offloads that would require the use of tidal windows.

10.3.3.4.3 Offsite MOF Considerations

As an alternative to the proposed onsite location for the MOF, existing marine docks north of the Liquefaction Facility site were considered. For example, the Applicant considered use of the existing Offshore Systems Kenai facility. This facility is located approximately 1 mile north of the Liquefaction Facility site and includes a 600-foot dock; an on-dock warehouse; an onshore warehouse, heliport, and hangar buildings; fuel storage and distribution facilities; outside storage; and staging pads. However, after initial review, this alternative was not considered further because it would not minimize the haul/transit distance to the Liquefaction Facility site. Further, the facility and associated infrastructure would require significant upgrades to accommodate high volume (1+ million tons), large size, and heavy weight of cargoes (i.e., modules weighing from 1,000 tons up to 6,000 tons) anticipated during the construction phase. Material coming into this facility would still need to be transported via truck on the Kenai Spur Highway south to the site, which would lead to greater travel times, fuel use, emissions, and traffic constraints moving back and forth in front of the neighboring facilities north of the site. The site would require significant redevelopment to meet the needs of the Project, including:

- Improved structural and bearing capacity to accommodate heavy cargoes (up to 6,000 tons);
- Additional berths to accommodate high cargo volumes (1+ tons) with offloads from a variety of cargo vessels (barges, heavy-lift geared ships, and module carriers); and
- Upgraded infrastructure (including laydown areas, access roads, etc.) to enable safe transport of large modules and equipment to the site.

The existing Rig Tenders dock facility, located approximately 1.7 miles north of the Liquefaction Facility site, was also considered. The outer dock face of the facility is approximately 600 feet long and could potentially be used to accommodate Lo-Lo vessels. However, the limited window for vessels to stay afloat poses operational challenges to offloading cargoes before grounding the vessel. Ro-Ro vessels could also be accommodated here. Highway access to the site also currently exists. The facility has been used and may be used in the future for loading modules onto barges for transport to Alaska's North Slope and other destinations.

Only a small number of berth positions and alignments were considered potentially feasible for MOF construction at the Rig Tenders facility because it is used for other operations and clients. This would require dredging and quay construction to facilitate the number of vessels for the Project. The site is not considered the Applicants' proposed alternative because:

- The site would require considerable upgrading;
- The site could not accommodate three berths with sufficient depth for vessels to stay afloat, which is part of the Applicants' current proposed alternative MOF design. Preliminary evaluation of different designs indicates only two berths could be accommodated at this site;
- There is an additional distance to haul the modules and equipment from this alternative site to the Liquefaction Facility along the Kenai Spur Highway; and
- The majority of the existing facility operations would need to be shut down during peak use by the Project, or the facility would need to be expanded, resulting in equivalent MOF impacts on a site outside of the Liquefaction Facility.

Although not considered the Applicants' proposed alternative for peak construction, these sites may be considered for use in early stages of the Project while the MOF is being constructed.

10.3.4 Liquefaction Facility Design Alternatives

10.3.4.1 LNG Plant

10.3.4.1.1 Liquefaction Alternatives

Liquefaction technology alternatives include:

- Propane Pre-Cooled Mixed Refrigerant (AP-C3MRTM) Process – Air Products and Chemicals, Inc.;
- AP-XTM Process – Air Products and Chemicals, Inc.;
- Optimized Cascade® process – ConocoPhillips;
- Dual Mixed Refrigerant (DMR) Process – Shell;
- Nitrogen Expansion – Wärtsilä Hamworthy;
- PRICO® SMR – Black & Veatch; and
- OSMR® – LNG Technology.

The Applicant has determined that the AP-C3MR™ Process is the proposed alternative for the Project. The rationale for this selection is as follows:

- The large gas reserve available for the Project can be more economically liquefied using one of the first four technologies listed. The AP-X process handles capacities of up to 9 MTPA per train (plant configuration would be two trains of nominally 9.X MMTPA), but was not selected as the proposed alternative due to possible execution risk involved with upsized equipment and piping in the two trains. The AP-C3MR™ technology can produce up to 7 MTPA per train, thus is more compatible with the three trains in the upstream GTP.
- Mixed refrigerant processes such as AP-C3MR™, AP-X Process, and DMR are highly efficient. The mixed refrigerant is tailored for the composition of the feed gas from the North Slope to optimize the cooling curves.
- The design of each LNG train proposed for the Project is based on numerous AP-C3MR™ LNG projects built and in operation throughout the world. This helps provide certainty of outcome for the Project.

The AP-C3MR™ is aligned with the Project attributes of gas supply and train capacity, while sustaining Project targets relating to certainty of outcome, economics, environment, operability, and safety. None of the listed liquefaction technologies have a discernable environmental advantage over the other alternatives.

10.3.4.1.2 Facility Energy Needs

The Liquefaction Facility energy needs can be broken into three basic design categories:

- Refrigerant compression – approximately 550 megawatts of power would be required to drive the C3 and mixed refrigerant compressors;
- Process cooling – a range of approximately 22 megawatts of electric power would be required to support cooling; and
- Other power – approximately 114 megawatts of electric power would be required to support operation of the Liquefaction Facility beyond refrigerant compression and cooling needs.

These approximate values represent the current basis of design.

10.3.4.1.3 Facility Energy Supply Alternatives and Environmental Impacts

10.3.4.1.3.1 Refrigerant Compression Alternatives

Like domestic air conditioning and refrigeration systems, the Liquefaction Facility would compress refrigerants to provide the source of cooling needed to convert natural gas to LNG. To do this, mechanical power is needed to turn the compressors. The Applicant has considered whether to drive the refrigeration compressors with natural gas turbines or electric motors (eLNG). As shown in Table 10.3.4-1, natural gas turbines were considered with or without associated steam generators that would be used to power a steam turbine to generate electricity. Heat for steam generation would be sourced from gas turbine exhaust.

TABLE 10.3.4-1

Comparison of Liquefaction Refrigerant Compression Driver Alternatives

Evaluation Criteria		Alternatives: Mechanical Drive Natural Gas Turbine without Steam Generator (Applicants' proposed alternative)	Alternatives: Mechanical Drive Natural Gas Turbine with Steam Generator	Alternatives: Electric Motor Drive (eLNG)
Engineering/Technical Considerations	Process	A natural gas turbine is coupled directly and turns (drives) the refrigerant compressor	Similar to the proposed alternative, but a steam generator is included that makes use of hot turbine exhaust to create steam to generate electric power	An electric motor is coupled to a variable-frequency drive, which drives the refrigerant compressor; electric power is generated by natural gas turbines (simple or combined cycle) in another area of the facility
	Design	Simplest, most conventional design; enables increased standardization of equipment	Most complex – adds utility piping/instrumentation and introduces steam/freeze protection issues to process area	Increased number of drivers – gas turbine drives electric generator, electric motor drives refrigerant compressor Limited engineering, procurement, execution, and operating experience

TABLE 10.3.4-1

Comparison of Liquefaction Refrigerant Compression Driver Alternatives

Evaluation Criteria		**Alternatives**		
		Mechanical Drive Natural Gas Turbine without Steam Generator (Applicants' proposed alternative)	**Mechanical Drive Natural Gas Turbine with Steam Generator**	**Electric Motor Drive (eLNG)**
				with large electric motors drives in this application Large variable speed drive systems more complex
	Construction	Easiest to construct	Most complex to construct	More complex to construct
	Operability	Highest (best) operability – requires lowest coordination with electric power supply	Lowest operability – requires close coordination of facility electric power supply and demand with varying mechanical drive operation Increases risk of plant trips and associated emissions release	Median operability – requires coordination of electric power supply
Environmental	Footprint	Lowest	Highest	Median
	Water	Minimal consumptive water use and wastewater generation	Consumptive water use for steam generator make-up and steam condensing cooling system; wastewater from water treatment and blowdown	Depends whether electric power is provided by simple cycle or combined cycle generation mode
	GHG Emissions[a]	Highest – expected to result in lowest thermal efficiency and highest fuel consumption	Median to lowest	Median to lowest – depends whether electric power is provided by simple cycle or combined cycle generation mode
	Other Air Emissions (nitrogen oxide [NOx], etc.)[a]	Highest – depends on specific suite of emissions controls	Median to lowest – depends on specific suite of emissions controls	Median to lowest – depends whether electric power is provided by simple cycle or combined cycle generation mode
	Noise	Lowest – no additional noise from condenser fans	Highest – incremental noise from condenser fans	The same or lower than steam generator alternative, depends on power generation mode
	Visual Aesthetics	Lowest – turbine exhaust less prone to vapor plume formation	Highest – vapor plumes from turbine exhaust	The same or lower than steam alternative, depends on power generation mode
Cost		Lowest	Median	Highest

[a] All alternatives are bounded by Best Available Control Technology (BACT) for GHG and other emissions under the Clean Air Act.

Cogeneration (also called "combined heat and power" or CHP) is a process that could be applied to mechanical drive natural gas turbines, but was not considered as an alternative for refrigerant compression. Although cogeneration (using less complex waste heat recovery units [WHRUs] rather than steam generators) would score high on many evaluation criteria, the lack of significant process heat needs precludes their application. Limited application of waste heat recovery may still occur for space heating or other heat needs.

The Applicant evaluated natural gas turbines and electric motor refrigerant compressor drive alternatives. Although eLNG results in higher availability and higher LNG production on a standalone basis, concerns exist as to whether the increased LNG volumes could be captured on an integrated Project basis (misalignment of the planned maintenance with the Mainline and the GTP). Although eLNG could result in slightly lower overall facility air emissions, the scale of the emission reductions is dependent on how the electricity that powers the compressor drive motor is generated (analogous to electric vehicles). The more-significant emissions reductions associated with use of combined cycle power generation would come at a cost of new impacts to consumptive water use, wastewater generation, noise, and visual aesthetics (see Tables 10.3.4-1 and 10.3.4-3 for details).

Likewise, including steam generators on mechanical drive natural gas turbines would result in lower air emissions, with similar increased impacts related to water, noise, and visual aesthetics. Steam generators also result in compromises related to process, design, construction, and operability (Table 10.3.4-1).

For refrigerant compression, the Project has selected mechanical drive natural gas turbines without steam generators as the Applicants' proposed alternative. This proposed alternative is consistent with the design of most liquefaction facilities currently being planned or built. While it results in slightly higher air emissions, it offers fewer impacts related to water, noise, and visual aesthetics. Mechanical drive natural gas turbines without steam generators offer a number of practicability benefits related to process, design, construction, operability, and cost (Table 10.3.4-1).

The Applicant is currently evaluating available mechanical drive natural gas turbine models to determine the proposed models to drive refrigerant compression. Different turbine types, makes, and models may have differing environmental impacts (as well as engineering issues/opportunities) and are being evaluated as part of the current engineering optimization effort.

10.3.4.1.3.2 Process Cooling Alternatives

Three alternative cooling system options were evaluated for providing the cooling required for the Liquefaction Facility:

- Air cooling;
- Standalone closed loop cooling water using a cooling tower; and
- Standalone closed loop cooling water using air coolers.

These alternatives were evaluated for the cooling loads of the liquefaction trains, fractionation area, and BOG area. Each cooling system alternative was evaluated based on the following criteria: power requirements and related fuel gas consumption, footprint requirements, water requirements, air emissions, noise levels, visual aesthetics, and cost.

A comparison of the alternatives is provided in Table 10.3.4-2.

TABLE 10.3.4-2

Comparison of the Cooling System Alternatives

Evaluation Criteria		Alternatives: Air Cooling (Applicants' proposed alternative)	Alternatives: Closed Loop Cooling Water Using a Cooling Tower	Alternatives: Closed Loop Cooling Water using Air Coolers
Engineering/Technical Considerations	Process	Cooled directly with atmospheric air using air coolers. The air is drawn over tube bundles by the use of fans, in turn cooling the process fluid within the tube bundles. For this option, no additional utility equipment is required, only the air cooler units.	Cooled directly with cooling water in a closed loop circulating system Heat is removed from the circulating system using a cooling tower.	Cooled directly with cooling water in a closed loop circulating system Heat is removed from the circulating system using an air cooler.
	Power Requirements	22 megawatts	28.5 megawatts	54 megawatts
Environmental	Footprint	A large plot space is required for the trains to accommodate the required number of air cooler bays. However, the space needed can be reduced by installing the air coolers on pipe racks in modular designs, resulting in a negligible difference in the required footprint from the alternative of a closed loop cooling using a cooling tower.	The process coolers would be smaller units than the air coolers. However, the cooling tower would require a large footprint, anticipated to be approximately 1.6 acres and may not be suitable for modularization.	A large plot space is required for the trains to accommodate the required number of air cooler bays. However, the space needed can be reduced by installing the air coolers on pipe racks in modular designs, resulting in a negligible difference in the required footprint from the alternative of a closed loop cooling using a cooling tower.
	Water Use	N/A	Initial filling of the system and make-up water at an approximate rate of 5,350 gallons per minute The circulating water will require chemical dosing, which may include but is not limited to: pH control, corrosion inhibitor, or agents to prevent biological growth. The blowdown[a] water would require treatment prior to disposal, requiring either a dedicated effluent system or additional site effluent system capacity.	Initial filling of the system with minimal makeup water needed at an approximate rate of 44 gallons per minute The circulating water would require chemical dosing. This may include, but is not limited to, a corrosion inhibitor.

TABLE 10.3.4-2

Comparison of the Cooling System Alternatives

Evaluation Criteria		Alternatives		
		Air Cooling (Applicants' proposed alternative)	**Closed Loop Cooling Water Using a Cooling Tower**	**Closed Loop Cooling Water using Air Coolers**
	Air Emissions	Higher fuel use and related emissions than water cooling with a cooling tower	Water is lost into the atmosphere in the discharge air stream through evaporation and as drift, where water droplets are being entrained in the discharge air stream and becoming particulate matter. Lowest fuel use	Highest fuel use and related emissions
	Noise	Elevated fans on the air coolers would be a new source of noise and relatively louder than the alternative of closed loop cooling water using a cooling tower. Noise could be reduced with selection of lower noise level fan options.	Elevated fans on the cooling tower would be a new source of noise. Noise could be reduced with selection of lower noise level fan options.	Elevated fans on the air coolers would be a new source of noise and relatively louder than the alternative of closed loop cooling water using a cooling tower. Noise could be reduced with selection of lower noise level fan options.
	Visual Aesthetics	No elevated structure required beyond that of the plant itself	Requires a cooling tower that would have a visible vapor plume	No elevated structure required beyond that of the plant itself
Cost		Lowest construction cost; higher operating costs than the water cooling tower alternative	Higher construction cost than air cooling; lowest operations costs	Lower construction costs than the water cooling tower alternative; highest operational costs

[a] Water stream is released to control the level of dissolved solids in the circulating system

The Applicants' proposed alternative is use of an air cooling system. In contrast to the other alternatives, the use of an air cooling system would not require continued water use and treatment, and would require the least amount of power. In addition, use of water with a cooling tower has the potential for evaporation and drift losses that could contain minor concentrations of the chemicals used for water treatment and particulates resulting in airborne emissions. Also, under some conditions, the moist air emitted can result in a visual plume from the cooling tower, which may contribute to fogging and, in a cold environment like Alaska, could result in ice formation on ground surfaces or vegetation.

10.3.4.1.3.3 Electric Power Alternatives

The Applicant investigated the availability and capacity of the local utility (Homer Electric Association [HEA]) to supply power for operations and determined that it does not have sufficient capacity to provide for the Project needs at the Liquefaction Facility. The local utility would be required to construct a similar-sized power generation facility to supply the capacity required by the Project. In addition, there would be additional environmental impacts associated with routing these added power supply lines to the Liquefaction Facility site. However, use of the existing HEA utility system for construction power requirements and essential load (i.e., emergency power during operations) was considered to be a viable alternative and included in the Project design.

Alternatives for electric power supply based on renewable energy sources were not developed. The lack of alternatives is based on the Project's need for a consistent, reliable supply of power that could not be met by any potential renewable energy option.

Table 10.3.4-3 provides an evaluation of electric power alternatives that were considered for the Project. These alternatives are based on the need for a consistent, reliable supply of power that is principally generated on site. Natural gas is the fuel common to all of the options, given its availability in necessary quantities via pipeline to the Liquefaction Facility. In addition, natural gas inherently has fewer environmental impacts compared to other fuels available in sufficient quantities to the Project.

TABLE 10.3.4-3

Comparison of Liquefaction Electric Power Alternatives

		Alternatives (Applicants' Proposed Alternative Not Yet Determined)		
Evaluation Criteria		**Simple Cycle Industrial Natural Gas Turbines**	**Simple Cycle Aeroderivative Natural Gas Turbines**	**Combined Cycle Natural Gas Turbines**
Engineering/Technical Considerations	Process	Uses heavy-duty industrial gas turbine engine where power turbine and auxiliaries (air inlet, lube oil, cooling, exhaust, etc.) are combined into a single unit	Uses lighter aircraft-designed turbine engine packaged with a power turbine and auxiliaries to provide the same function as an industrial turbine	Uses exhaust gas from an industrial or aeroderivative natural gas turbine to generate steam; steam is used to drive a separate steam turbine; both natural gas and steam turbines drive electric power generator
	Design	Less complex than combined cycle, similar to aeroderivative turbines	Similar to slightly more complex than industrial turbine module, depending on whether skid components ("jet," power turbine, etc.) are pre-packaged or require custom skid integration.	Most complex – requires addition of steam turbine, as well as steam generating, water treatment and steam-condensing equipment
	Construction	Slight increase in construction complexity over aeroderivative turbines	Simplest to construct – lightest component weights	Most complex to construct
	Operability	Less complex than combined cycle, on par with aeroderivative turbines	Less complex than combined cycle, on par with industrial turbines	Most complex to operate; lag time for steam turbine electric generation on start-up
Environmental	Footprint	Slight increase over aeroderivatives	Lowest	Highest

TABLE 10.3.4-3

Comparison of Liquefaction Electric Power Alternatives

Evaluation Criteria		Alternatives (Applicants' Proposed Alternative Not Yet Determined)		
		Simple Cycle Industrial Natural Gas Turbines	**Simple Cycle Aeroderivative Natural Gas Turbines**	**Combined Cycle Natural Gas Turbines**
	Water	Minimal consumptive water use and wastewater generation	Minimal consumptive water use and wastewater generation	Consumptive water use and wastewater for steam generator makeup; potential for consumptive water use and wastewater from water treatment and cooling tower blowdown (depends whether air or water cooling is used)
	GHG Emissions[a]	Highest – typically results in lowest thermal efficiency and highest fuel consumption	Median – typically results in higher thermal efficiency and lower fuel consumption than an industrial turbine	Lowest – typically results in higher thermal efficiency and lower fuel consumption than simple cycle options
	Other Air Emissions (NOx, etc.)[a]	Typically higher for GHG than combined cycle, depends on specific suite of emissions controls	Typically higher for GHG than combined cycle, depends on specific suite of emissions controls	Likely lowest for GHG – less overall fuel consumption and lower temperature exhaust; more amenable to certain emission controls
	Noise	Lower – no additional noise from cooling fans	Lower – no additional noise from cooling fans	Highest – incremental noise from cooling fans
	Visual Aesthetics	Lower impact – no vapor plume from cooling towers and turbine exhaust less prone to vapor plume formation	Lower impact – no vapor plume from cooling towers and turbine exhaust less prone to vapor plume formation	Highest impact – vapor plumes from turbine exhaust and cooling towers (cooling tower impacts depend on whether air or water cooling is used)
Cost		Lower	Lower	Highest

[a] All alternatives are bounded by BACT for GHG and other emissions under the Clean Air Act.

The Applicant has not yet determined whether the proposed alternative is combined cycle mode natural gas turbines or one of two types of simple cycle mode natural gas turbines. The emissions reductions associated with use of combined cycle power generation would result in additional consumptive water use, wastewater generation, noise, and visual aesthetics (see Tables 10.3.4-1 and 10.3.4-3 for details). In addition, several different turbine makes/models are under evaluation. Different turbine makes and models may have differing environmental impacts (as well as engineering issues/opportunities) and are being evaluated as part of the current engineering optimization effort.

10.3.4.1.3.4 Flare Design Alternatives

The Liquefaction Facility would contain a Wet Flare, Dry Flare, and Low Pressure (LP) flare. For the wet and dry flares, two alternative flare system types were evaluated:

- Elevated flares – A wet and dry elevated flare system consisting of three risers for the dry flare, one riser for the wet flare, and one spare riser common for both the wet and dry flare; and
- Multipoint ground flares – A wet and dry ground flare with a common radiation fence.

Use of an elevated flare system was the only alternative considered for the LP flare at the Marine Terminal. Potential use of a ground flare was not considered practicable due to the flare's location in relation to the trestle and the need to keep the flare away from the operations on the trestle and at the berths. In addition, a subsonic (low-velocity) flare is selected for the LP flare to minimize noise during relief events.

The two alternative wet/dry flare systems were evaluated based on the following criteria: maintenance requirements, smokeless capacity, footprint requirements, air emissions, noise levels, visibility to nearby public, and cost.

A comparison of the elevated and ground flare system alternatives is provided in Table 10.3.4-4.

Use of a multipoint ground flare is the Applicants' proposed alternative. The ground flare system requires a smaller footprint around the flare operations, has reduced visibility since it is ground based, and has a lower noise impact. In addition, the majority of the required maintenance activities can be performed from outside of the radiation fence (fence around flare operations footprint).

TABLE 10.3.4-4

Comparison of the Flare System Alternatives

Evaluation Criteria		Alternatives: Multipoint Ground Flare System (Applicants' proposed alternative)	Alternatives: Elevated Flare System
Engineering/Technical Considerations	Maintenance	The majority of maintenance activities can be performed in a safe region outside the fenced area. However, installation of a spare flare is required to perform maintenance inside the fence without plant shutdown.	Installation of spare flare is required to perform maintenance activities without plant shutdown. It may be required to remove the flare tip from the flare stack for maintenance.
	Smokeless Capacity	Smokeless operation can be achieved by pressure-assisted multipoint ground flares.	The system requires air-assist to achieve smokeless operation; smokeless capacity is therefore limited.
Environmental	Footprint	Each of the three units would be approximately 260 feet wide, 350 feet long, and 50 feet in height, resulting in an area of approximately 6.3 acres. While the ground flare takes up more physical plot space, there would be no radiation at grade outside the ground flare fencing, because the flame would be completely shielded. Thus other equipment, buildings, etc., can be located in close proximity to the ground flare.	A single elevated flare would stand approximately 420 feet tall. While the actual physical footprint of the flare stack is minimal, it has a flare radius for the 500 British thermal unit/hour/square foot radiation limit of approximately 1,100 feet. This results in a footprint of approximately 87.2 acres or about 14 times greater than the ground flare.[a]

TABLE 10.3.4-4

Comparison of the Flare System Alternatives

Evaluation Criteria		**Alternatives: Multipoint Ground Flare System (Applicants' proposed alternative)**	**Alternatives: Elevated Flare System**
	Air Emissions impacts	Depends on flare design; however, due to elevation impacts would generally be anticipated to be higher at the Liquefaction Facility fence line than for an elevated flare	Depends on flare design; however, generally anticipated to be lower at the Liquefaction Facility fence line than for a ground flare
	Noise	Similar noise signature as an elevated flare; however, noise could be reduced through the radiation fence around the units, as well as distance to the Liquefaction Facility fence line	Noise similar to that of a ground flare, but distributed from a higher elevation, resulting in greater distribution of the noise around the site.
	Visibility	The flare is hidden behind the radiation fence and is not visible from ground level. Illumination may occur during high load periods at night, depending on the visible light present in the atmosphere and reflection from any low cloud cover.	Flame highly visible when flaring
Cost		Higher construction costs; anticipated lower operations and maintenance costs	Lower construction costs; anticipated higher operations and maintenance costs

10.3.5 Marine Terminal

10.3.5.1 PLF Trestle Design

Because the proposed PLF extends from the shoreline to deeper water (-53 feet MLLW), the PLF was divided into two segments to consider alternative designs and installation methods based on the water depth for each trestle segment. In deep-water, large cranes working from barges could be used to install the trestle and these barges would remain afloat through all stages of the tide. In the shallow-water segment, only jack-up barges or land-based cranes working on top of the trestle itself would be feasible options to install the trestle. Shallow water in this context is from shore out to approximately -25 feet MLLW. The deeper-water segment is defined as water depths from -25 feet MLLW to approximately -53 feet MLLW, where the loading platform would be attached to the trestle.

An assessment of the design alternatives considered for each segment is provided in the following sections.

10.3.5.1.1 Shallow-Water Segment

The trestle design must be able to support the proposed pipe rack and roadway modules. The total weights of the 120-foot pipe rack and roadway sections are 200 and 75 tons, respectively. Two typical design concepts were evaluated to support the trestle: a single large-diameter monopile and multiple pile bents with both vertical and batter piles (i.e., a pile driven at a slight angle to resist a lateral force).

The two trestle support designs were evaluated based on: 1) their ability to withstand seismic and potential ice load conditions of Cook Inlet; 2) the amount of underwater sound generated during their installation; 3) the practicality of using these designs under the conditions of the site and general conditions during construction; and 4) cost.

A comparison of the trestle support design alternatives in shallow water is provided in Table 10.3.5-1. The Applicants' proposed alternative design is to use multiple pile bents (with vertical and batter piles) to enable an overhead construction method as the piles are lighter, can be placed and driven into the substrate relatively quickly, and offer resilience to withstand the high forces expected in the seismic and ice conditions.

TABLE 10.3.5-1

Comparison of the PLF Shallow Water Trestle Foundation Alternatives

Criteria		Alternatives	
		Multiple Pile Bents with Vertical and Batter Piles (Applicants' Proposed Alternative)	**Monopile**
Engineering/Technical Considerations		Traditionally pile bents with a combination of vertical and batter piles (typically three to four piles per module) have been adopted on the majority of LNG projects. The raking piles are effective in taking lateral loads such as wind, seismic, and waves; however, they can attract more seismic load due to their overall stiffer response to lateral loads.	Used on neighboring trestles in the Nikiski area and have the advantage of better ice clearing abilities than multiple pile bents
Environmental	Noise	Would require pile driving with a relatively smaller hammer than the monopile	Requires very large piling hammers or drilling of a borehole. Peak sound levels are anticipated to be 205 decibels (dB) at approximately 33 feet from the sound source.
Practicability of Construction		Have been adopted on the majority of LNG projects	Relatively heavy (approximately 250 to 300 tons for an 80-foot span) and would not be manageable in one piece in shallow water.

10.3.5.1.2 Deep-Water Segment

In water depths greater than -25 feet MLLW, it is anticipated that large crane barges with crane capacities in excess of 500 tons would be used to install the foundations for the trestle and platforms, as well as the topside modules such as the pipe racks and platform decks.

Following a preliminary survey of the available U.S.-flagged crane barges, it was decided to limit the maximum lift weight for a topside module to 500 tons to ensure there would be U.S.-flagged vessels capable of carrying out the work. Module lengths of 160 feet, 200 feet, and 240 feet were considered, however, only the 160-foot module was within the lifting capabilities of these vessels.

Preliminary estimates of the lateral (seismic and ice) and vertical (module weight) forces on the foundations indicated that they would be very similar to those encountered in the design of offshore wind turbines in the North Sea from high wind, waves, and currents. As the loads, water depths, and construction schedules are relatively similar, it is expected that the foundation solutions used in offshore wind farms may be applicable to the Project. The three most common foundation solutions used for offshore windfarms in the North Sea are: 1) large-diameter (12 to 18 feet) monopiles; 2) gravity-based (typically concrete) structures; and 3) steel-jacket (quadropod) foundation with multiple pin piles.

The most commonly used alternative is the driven monopile foundation; however, more recently, jacket-type foundations have been investigated in cases where water depths exceed 80 feet as the diameter and weight of the monopile solution exceeded the lifting capacity of many of the first-generation installation vessels.

The deep-water trestle foundation alternatives were assessed by comparing these criteria: 1) whether the design was suitable for high seismic zones and ice load conditions of Cook Inlet; 2) what the footprint of the seafloor disturbance was; 3) marine sound levels generated during construction; 4) the practicality of installing the design in the conditions found in Cook Inlet; and 5) the cost.

A comparison of the three foundation alternatives is provided in Table 10.3.5-2.

The Applicants' proposed alternative is to use a jacket foundation for the deep-water segment of the PLF trestle. Although it is likely to be more expensive than the use of the monopile alternative, the monopile alternative has a number of high-risk factors associated with it, including finding a suitable installation vessel (practicality of installation in Cook Inlet), and that the high sound levels during installation would require extensive mitigation measures to work in ESA Beluga Whale CHA 2.

TABLE 10.3.5-2

Comparison of the Product Loading Facility (PLF) Deepwater Trestle Foundation Alternatives

Criteria			Design Alternatives		
			Steel-Jacket Quadropod (Applicants' Proposed Alternative)	**Monopile**	**Gravity-Based Structure**
Engineering/Technical Considerations	Design		Quadropod – a large-diameter stem (8 feet) supported by four legs. The jacket has bracing extending from the main shaft out to the pile sleeves at the four corners. The bracing would be deliberately placed below the water line to prevent ice interacting with the bracing.	The design would have a narrower 10-foot-diameter tubular section from -10 feet MLLW to the underside of the pile cap. This is to reduce the ice loads on the structure as they increase proportionally to the diameter.	Either steel or concrete structure to hold the trestle sections, including a base about 80-foot in diameter. The large diameter of the base would be required to prevent overturning and sliding. Rock would also be required as scour protection around the base of the structure. An alternative to the steel gravity base solution would be to fabricate it in concrete.
Environmental	Seafloor Disturbance	Footprint	Would not require an additional support structure on the seafloor (1/100 of the footprint of the gravity based structure per quadropod)	Would not require an additional support structure on the seafloor (1/100 of the footprint of the gravity-based structure per quadropod).	Would require a large structure to be placed on the seafloor, including scour protection (each structure would be 0.11 acre)
		Dredging	None required	None required	Would require dredging about 0.2 acre per structure to level the seabed for placement

TABLE 10.3.5-2

Comparison of the Product Loading Facility (PLF) Deepwater Trestle Foundation Alternatives

Criteria		Design Alternatives: Steel-Jacket Quadropod (Applicants' Proposed Alternative)	Design Alternatives: Monopile	Design Alternatives: Gravity-Based Structure
	Noise	Would require pile driving of relatively small pins using a smaller hammer than the monopile. Peak sound levels are anticipated to be 195 dB at approximately 33 feet from the sound source, but for a longer duration than monopoles.	Would require very large piling hammers if drilling cannot be performed for installation Anticipated to have peak sound levels of approximately 205 dB at approximately 33 feet from the sound source	Limited to vessel noise and rock dumping during installation
Practicability of Construction	Weight Considerations	The total weight of the jacket excluding the four pin piles and the headstock is approximately 450 tons.	The total weight of the steel structure (excluding the headstock) would be approximately 800 tons. The portion that would be required to be lifted in one piece (i.e., up to the grouted connection) would be approximately 550 tons.	The total weight of the steel structure is approximately 1,900 tons. Due to the weight of the foundation, it is unlikely that it could be lifted into place, but would need to be floated and sunk.
	Installation	Have been successfully used in offshore windfarms and installed using either jack-up barges or a jack-up ship	The pole would stand far above the seabed. No vessels in the current U.S. fleet are known to have the capabilities of the required installation and the ability to operate in relatively shallow water. However, some may be commissioned in the next few years to support the U.S. offshore wind industry.	Due to the high tidal range and tidal currents, installation would be highly challenging.
Cost		More expensive than monopile	Least expensive	Most expensive

10.3.5.2 Navigational Channel Alternatives

LNGC transit routes in Cook Inlet were proposed as part of the USCG's Waterway Suitability Assessment (WSA). The WSA addresses the safety and security aspects of transit from the entrances of Cook Inlet to and from the proposed Liquefaction Facility site. LNGCs would transit Cook Inlet in accordance with state and federal pilotage requirements.

In the region of Cook Inlet where the Marine Terminal would be located, navigational channels are not present due to the adequate depth of the Inlet in this area. The proposed LNGC routes would follow existing transportation corridors in Cook Inlet; alternatives are not required because a dredged channel leading to the Marine Terminal would not be required.

10.4 PIPELINE ALTERNATIVES

10.4.1 Mainline System Alternatives

System alternatives evaluated for the Mainline, an approximate 807-mile pipeline constructed between the Liquefaction Facility and the GTP on the North Slope, include existing pipeline systems and planned or proposed pipeline systems.

10.4.1.1 Use of Existing Pipeline Systems, With or Without System Upgrade

10.4.1.1.1 Trans-Alaska Pipeline System (TAPS) Alternative

The TAPS crude oil pipeline is the only existing pipeline system that extends from the North Slope to Southcentral Alaska. It is an 807-mile-long, 48-inch-diameter crude oil pipeline that currently transports crude oil from the North Slope to a tanker terminal in Valdez, Alaska.

TAPS presently has capacity to accommodate additional crude oil throughput, including crude oil produced from future development in undeveloped onshore and offshore leases. The potential for the need to accommodate future production suggests there is a benefit to not changing TAPS configuration in the near future. Use of TAPS for this Project as an alternative to the Project raises the following issues:

- TAPS could not simultaneously transport oil and natural gas. The pipeline size is adequate; however, the pipeline wall thickness and steel properties are not appropriate for the volumes and pressure required for the Project. In addition, the pipe could not be retrofitted for gas transmission to provide the same volume of gas required. TAPS would also need to be retrofitted with multiple compressor stations to maintain pressure and temperature of the line (while delivering less gas throughput than the Liquefaction Facility requires) and potentially need additional liquids handling facilities to deal with liquids drop-out in outage scenarios. Therefore, an alternative means of transporting oil from the North Slope would need to be developed. This could include construction of a new, smaller-diameter oil pipeline along the same route, or transporting oil via tanker truck to the existing VMT.

- TAPS would need to be converted from a crude oil pipeline to a natural gas pipeline. An analysis to determine the feasibility of converting and certifying TAPS for natural gas transmission service in compliance with pipeline safety regulations would need to be completed to understand if this is a viable option.

- Because TAPS was designed and constructed to ship crude oil, it could not withstand the operating pressures planned for the proposed Mainline system. A reduction in Maximum Allowable Operating Pressure (MAOP) would thus be required, resulting in the reduction of natural gas flow capability through TAPS. Hydraulic simulations indicate a maximum natural gas flow capability through TAPS of approximately 1.5 billion standard cubic feet per day due to the lower MAOP after conversion to natural gas transmission service. The conversion of

TAPS to natural gas service would not allow sufficient gas volumes to be shipped to support the Project purpose.

- It is unlikely that the required compressor sites would align with existing pump station sites, requiring the development of compressor sites and the abandoning of pump station sites.

For these reasons, the option of converting TAPS for natural gas use as a portion of the Mainline (Proposed Alternative) is not considered a viable alternative; therefore, it was not analyzed in detail.

Use of the TAPS existing vertical support members (VSMs) for support of the Mainline was also considered. This would theoretically allow a portion of the proposed Mainline pipe to be above ground on existing VSMs, but the remainder of the proposed natural gas pipeline would still need to be buried. TAPS was not designed with the intent of accommodating a second pipeline. Each VSM site was evaluated to determine the design for that specific location, based on the soil conditions and weight of TAPS in operation. The crossbeams of each VSM have a coated steel shoe that allows for side-to-side movement of TAPS when it expands and contracts due to temperature fluctuations, and a second pipeline would interfere with this movement. The width, or span, of the crossbeam is too narrow to accommodate a second large-diameter pipeline. In addition, as discussed in Section 10.4.4, a high-pressure natural gas pipeline would not operate above ground without liquid dropout in the gas stream. Exposure of the steel pipeline to cold temperatures in the winter would require specially made steel, which is impracticable for Project costs to be competitive in the global LNG market. Therefore, use of TAPS VSMs for placement of the Mainline was not considered a viable alternative.

10.4.1.1.2 Use of Alternative Planned or Proposed Pipeline Systems

The following three alternative planned or proposed pipeline systems were identified and are described as follows.

10.4.1.1.3 Alaska Stand Alone Pipeline (ASAP) Project

The ASAP Project is a State of Alaska-sponsored project designed to deliver natural gas from Alaska's North Slope to Fairbanks, Anchorage, and as many other communities within the state as practical. The ASAP Project consists of a gas conditioning facility at Prudhoe Bay; a 733-mile, 36-inch-diameter, mostly buried pipeline from Prudhoe Bay to ENSTAR's existing gas distribution system near Anchorage at Big Lake; and a 30-mile, 12-inch-diameter lateral to Fairbanks (ASAP Public Scoping Report, November 25, 2014). The Project's distribution of natural gas from the projected 500 million standard cubic feet per day (MMSCF/D) is as follows (Alaska Gasline Development Corporation [AGDC], 2014):

- 200 MMSCF/D – Cook Inlet area current demand;
- 50 MMSCF/D – Cook Inlet area future demand (2030);
- 30 MMSCF/D – Fairbanks area future demand (2030); and
- 220 MMSCF/D – Future commercial and industrial use.

USACE, Alaska District, has been designated the lead federal agency and the Notice of Intent to prepare a Supplemental EIS (SEIS) was published August 1, 2014, which initiated a scoping comment period that ended on October 14, 2014. The current published timeline has construction of the ASAP Project occurring from 2018 to 2021 (AGDC, 2014). The ASAP Project is in the process of filing revisions to its pipeline route, working with the Alaska LNG Project to develop a common route with the Mainline where the two projects are in the same corridor. This has resulted in the two pipeline corridors being the same for approximately 82 percent, or 657 miles, of the proposed Project pipeline length. The Applicant filed a revised Section 404 CWA permit application on January 13, 2016, to address USACE comments. The USACE has deemed the application sufficient for continuation of the NEPA process. The schedule for updating the supplemental NEPA document has now been published by the USACE. The Applicant also submitted a ROW amendment request to the State of Alaska on January 15, 2016, and an updated ROW application to the BLM on January 15, 2016. The State of Alaska amendment request was public-noticed on February 5, 2016. The BLM has indicated a mid-February 2016 public notice date.

The ASAP Project would not meet the purpose and need of this Project because its pipeline design capacity is not sufficient to meet the throughput requirements of the Project. The environmental effects associated with expansion of the ASAP Project to meet the throughput needs of the Project, specifically the throughput needs of the Liquefaction Facility together with potential gas interconnection points, would likely be similar to those of constructing the Applicants' proposed alternative (Mainline). Currently the ASAP Project is on hold, other than the aforementioned SEIS/ROW work, while the state focuses its efforts on the Alaska LNG Project (see Section 1.3.2.1 of Resource Report No. 1 for the Project's throughput capacity). Therefore, use of the ASAP Project was not considered a viable alternative to the Project.

10.4.1.1.4 Alaska Pipeline Project (APP)

On May 1, 2009, FERC granted a pre-filing request for the APP (FERC Docket No. PF09-11-000), which would have consisted of the following components in Alaska:

- Approximately 58 miles of 32-inch-diameter pipeline from the PTU to a natural gas treatment plant near Prudhoe Bay; and
- Approximately 745 miles of 48-inch-diameter pipeline, extending from a natural gas treatment plant to the Alaska-Yukon border east of Tok, Alaska, including provisions for intermediate natural gas delivery points within Alaska.

The APP system would have been capable of transporting 4.5 billion standard cubic feet per day of natural gas and extend to pipeline facilities in Alberta, Canada, for markets in the contiguous North America, including the United States. However, this system does not meet the Project purpose and need (shipping LNG to foreign markets) with a pipeline route to Canada. On May 3, 2012, open season for the APP was terminated by its sponsors and the APP FERC docket was closed in 2015.

10.4.1.1.5 Denali – The Alaska Gas Pipeline (Denali Project)

On June 25, 2008, FERC granted a pre-filing request for the Denali – The Alaska Gas Pipeline Project (Denali Project) (FERC Docket No. PF08-26-000). The Denali Project planned to construct an Alaska natural gas transportation system, as defined by Section 103 of the Alaska Natural Gas Pipeline Act, which would consist of a 48- to 52-inch-diameter pipeline system between the Alaska North Slope and Alberta, Canada, capable of transporting about 4 billion cubic feet per day of natural gas. The Denali Project also planned to construct a new gas treatment plant on the Alaska North Slope.

The Project was consistent in design and routing to the APP. The Denali Project held an open season from July 6, 2010, through October 4, 2010. Subsequent to the open season, the Project was terminated. This system does not meet the Project purpose and need (shipping LNG to foreign markets) with a pipeline route to Canada.

10.4.2 Pipeline Route Alternatives

Pipeline route alternatives include major route alternatives, minor route alternatives, and route variations.

Major and minor route alternatives refer to deviations from the proposed Mainline alignments (PTTL had one route revision for aboveground design; there were no route alternatives for the PBTL). Major route alternatives are designed to avoid sensitive features, key infrastructure, or major terrain obstacles. The receipt and delivery points of major route alternatives are generally the same as the corresponding segments of the proposed pipeline; however, they could have substantially different alignments. Minor route alternatives are smaller in scale and designed to address similar issues at the local level. On a smaller scale, route variations are designed to avoid or reduce impacts on specific, localized resources including wetlands, residences, archaeological sites, and terrain constraints.

10.4.2.1 Routing Considerations

Routing a pipeline is an iterative process. When information is obtained that suggests a change to the pipeline route is warranted, a balanced evaluation of the environmental, social, engineering, construction feasibility, and costs are made. This determines whether a route refinement is the best solution. As a project progresses, new route information related to pipeline design, geotechnical conditions, construction planning, and environmental, regulatory, socioeconomic, and land considerations are identified and incorporated into the Project design as applicable. This iterative process continues until the pipeline is installed.

The Project developed the initial Mainline corridor (see Draft 1 of Resource Report No. 1, Appendix A) using information from prior projects for the route from the GTP south to Livengood. More than 30 years of work on various prior projects, as well as the ASAP routing effort, were used to identify a route within the preliminary corridor that was identified early in 2015. This route was Revision B, filed in the June 14, 2016 draft application for the Project, and focused on combining the ASAP route and this Project's Mainline. The Applicant has made further revisions to the Mainline, taking into consideration agency and scoping comments on the Rev B centerline, as well as other opportunities to further optimize the route. The resulting proposed Route Revision C2 was developed to minimize impacts and ensure the long-term integrity of the pipeline; comply with regulatory requirements; and to take into account constructability, safety, and cost considerations.

Because the pipeline would be a high-pressure system and mostly buried, criteria that are used to route the Mainline are: 1) shortest possible length considering all the factors that follow; 2) cost of installation and operation; 3) practicality of constructing the pipeline in the chosen route; 4) operability of the pipeline once installed, and meeting design standards and Pipeline and Hazardous Materials Safety Administration (PHMSA) requirements, which is a high consideration (Note: both 3 and 4 relate to avoiding stresses on the pipeline, steep topography, narrow ravines, excessive side slopes, geotechnically unstable areas, and areas of landslides or unstable slopes); 5) avoidance of Native allotments, Wild and Scenic Rivers, National Parks, NWRs, and Wilderness areas; 6) avoidance of NRHP-eligible sites; 7) avoidance of creating new ROWs—maximizing collocation; 8) avoidance of sensitive environmental features (listed species habitat, high quality wetlands, known nesting locations of listed species, etc.); 9) high-density populated areas; 10) open water features (ponds, lakes, reservoirs), focusing on crossing the narrowest portion of a waterbody; and 11) minimizing social impacts.

10.4.2.2 Collocation Considerations

Although installation of the Mainline along existing ROWs (such as powerlines, other pipelines, railroads, and roads) is often environmentally preferable to constructing a new ROW, it is also not always suitable to follow an existing ROW when considering the routing criteria listed in the previous section. FERC has defined collocation to mean placing the proposed pipeline within an existing ROW (wholly or partially). This minimizes the amount of new ROW that is cleared and/or maintained for a new pipeline.

However, placing a large-diameter (42-inch) pipeline within an existing ROW is not always practicable. A high-pressure, large-diameter natural gas pipeline has certain routing requirements (see previously listed criteria) that may not align with the criteria that were used to route the existing utility or road/railroad ROW. For instance, turning radii to maintain pipeline steel design standards and allow internal inspection tools to be used are a significant issue for operations. The pipeline would be required to maintain a radius on a pipeline turn that meets the engineering design requirements (steel characteristics) and operational requirements. This could require the Mainline to stop following the powerline ROW and create a new route that meets pipeline design and operations requirements.

Other criteria that are important to the pipeline are the need to bury the line as opposed to spanning over the landscape (powerlines), so adequate space is required to excavate, install, and cover the pipeline; ability to minimize impacts by crossing features at the narrowest location and on a perpendicular angle (many existing features cross without this regard); avoiding large waterbodies (roads, railroads, powerlines go over them); avoiding population centers (roads and railroads go through them); and avoiding environmental features (discussed in the following sections) to the extent possible. In many cases, the linear feature that would be collocated does not meet these criteria either because of how that linear feature was designed and constructed, or because of the regulatory requirements that were in force when it was constructed.

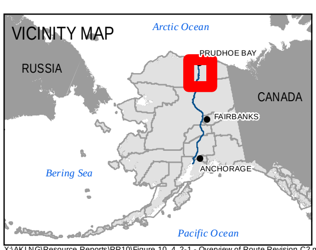
High-pressure natural gas pipelines also have safety considerations to incorporate into the routing design to address electrical mitigation (when routing alongside electric powerlines), safety zones (when routing alongside liquid or other pipeline systems), and routing considerations for construction execution needs (pipelines are built differently than roads, powerlines, and even pipelines laid decades ago, and therefore may need to leave the existing ROW to align across a waterbody, avoid an archaeological site, or to better align across a wetland to minimize the crossing length).

Specific to the Project, "collocation" is defined as where the Mainline parallels an existing road, pipeline, powerline, or railroad within 500 feet, with no overlap of the ROWs or placing of the Mainline in existing ROWs. Even the ASAP Project, when moving from a 24-inch pipeline to a 36-inch pipeline, moved its routing outside of the Parks Highway ROW. A discussion of the areas where the Project has collocated the Mainline and where it has not is summarized in the following sections.

10.4.2.2.1 Greenfield versus Collocation

Based on the Project's definition of collocation, the Mainline is collocated for approximately 34 percent of the route (see Resource Report No. 1). The proposed Route Revision C2 of the Mainline parallels existing corridors (Figure 10.4.2-1a-d), except for the portion from Livengood to Nenana, the portion along the west side of the Susitna River, and the small portion on the Kenai Peninsula. In those areas, there is little to collocate with for any appreciable distance. Table 1.3.2-2 of Resource Report No. 1 provides a summary of the route's collocation (i.e., within 500 feet) with existing ROWs along the route.

VICINITY MAP



X:\AKLNG\Resource Reports\RR10\Figure 10_4_2-1 - Overview of Route Revision C2.mxd

LEGEND

- Project Facility
- Existing Facility
- Alaska Place Names
- Alaska LNG Rev C2 Route
- Point Thomson Transmission Line (PPTL)
- Major Highways
- Trans Alaska
- Fiber Optic Cable
- Major Rivers
- Areas of Critical Environmental Concern
- State and Federal Conservation Lands

0 2.5 5 10 15 Miles

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PREPARED BY:	AGDC		
SCALE:	1:1,250,000		
DATE:	2017-03-16	SHEET:	A1

OVERVIEW OF ROUTE REVISION C2

A1 FIGURE 10.4.2-1

ALASKA LNG

VICINITY MAP

X:\AKLNG\Resource Reports\RR10\Figure 10_4_2-1 - Overview of Route Revision C2.mxd

LEGEND

- Alaska Place Names
- Alaska LNG Rev C2 Route
- Major Highways
- Trans Alaska
- Fiber Optic Cable
- Major Rivers
- Areas of Critical Environmental Concern
- State and Federal Conservation Lands

0 2.5 5 10 15 Miles

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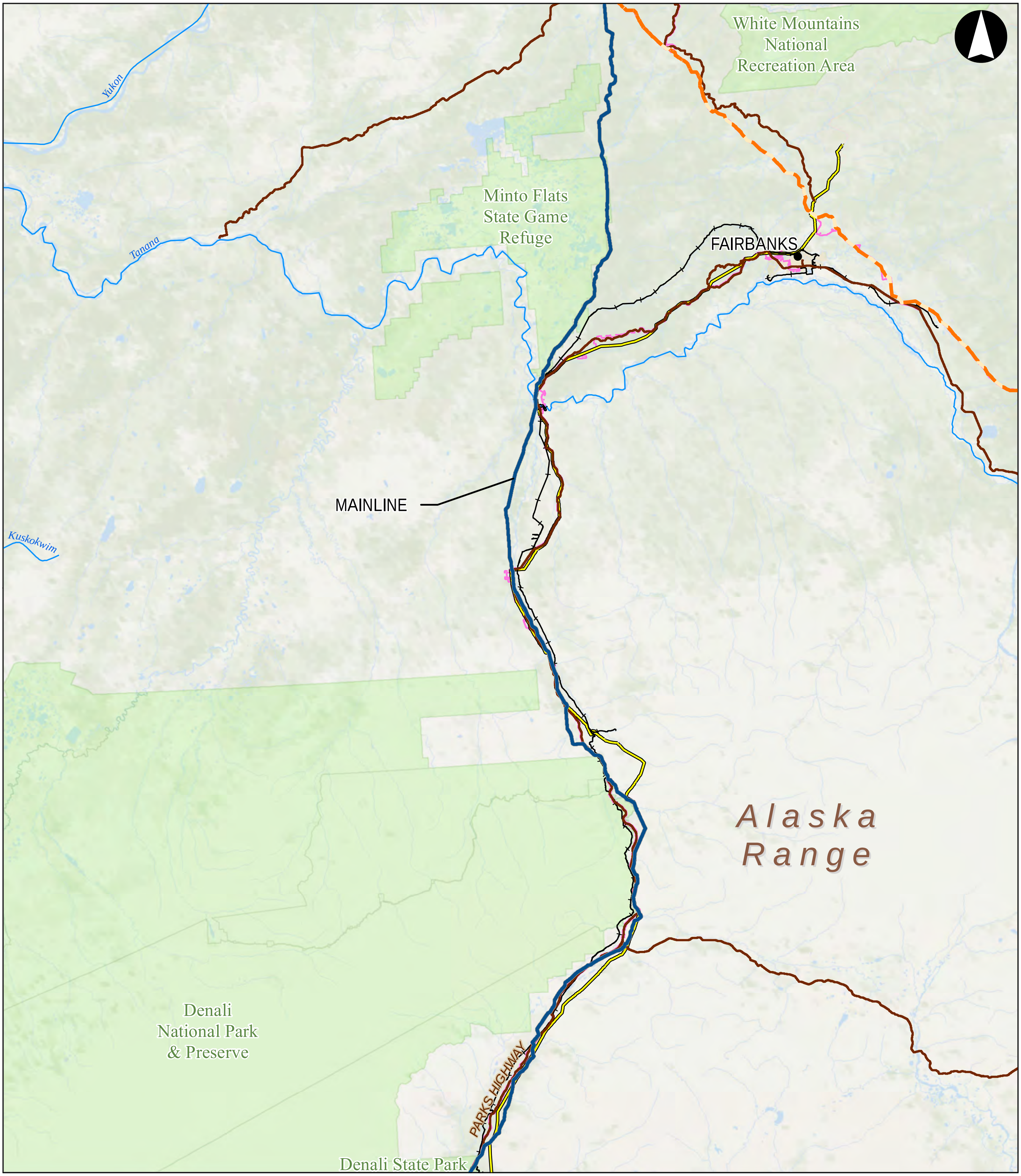
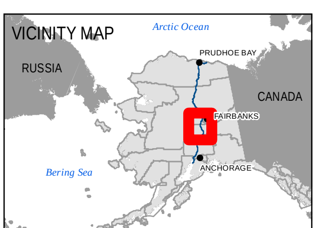
DATE:	2017-03-16	SHEET:	B1

OVERVIEW OF ROUTE REVISION C2

B1 FIGURE 10.4.2-1

ALASKA LNG





LEGEND

● Alaska Place Names	Major Highways
Alaska LNG Rev C2 Route	Trans Alaska
	Railroad
	Intertie
	Fiber Optic Cable
	Major Rivers
	State and Federal Conservation Lands

0 2.5 5 10 15 Miles

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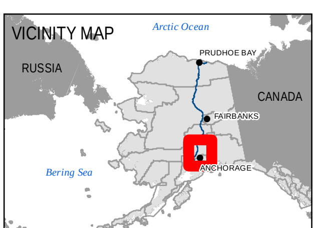
OVERVIEW OF ROUTE REVISION C2

C1 FIGURE 10.4.2-1

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_4_2-1 - Overview of Route Revision C2.mxd



X:\AKLNG\Resource Reports\RR10\Figure 10_4_2-1 - Overview of Route Revision C2.mxd

LEGEND

- Project Facility
- Alaska Place Names
- Alaska LNG Rev C2
- Major Highways
- Railroad
- Intertie
- Fiber Optic Cable
- Major Rivers
- State and Federal Conservation Lands

0 2.5 5 10 15 Miles

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PREPARED BY:	AGDC		
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DATE:	2017-03-16	SHEET:	D1

OVERVIEW OF ROUTE REVISION C2

D1 FIGURE 10.4.2-1

ALASKA LNG

There were limited routing options to evaluate because of the geographic considerations present in Alaska. Multiple east-west features limit the number of north-to-south routing options. The Brooks and Alaskan mountain ranges and major rivers, such as the Yukon and Tanana, form east-west barriers to routing that limit the number of options to cross these features. East-west barriers or features like this become natural funnels to north-south linear features, forcing them to cross only at a limited number of locations that are feasible from a construction and operations perspective. From Prudhoe Bay to Livengood, there is essentially one corridor that passes through the Brooks Range, crosses the Yukon River, and avoids other criteria such as National Parks and NWRs. Other features that traverse east-west across the study area that have limited the existing north-south linear corridors to the one existing utility corridor, are (from north to south): Sagwon Bluffs; Toolik Lake Research Natural Area;[17] Galbraith Lake ACEC;[15] Arctic NWR; Gates of the Arctic National Park and Preserve; Jim River ACEC;[15] Kanuti NWR; Yukon Flats NWR; Ray Mountain Range; White Mountains Natural Resource Area; Minto Flats SGR; DNPP; Denali State Park;[18] Susitna SGR; and Kenai NWR. As depicted in Figure 10.4.2-1a-d, these features have resulted in the existing, larger north-south linear infrastructure to follow the same general alignment as Route Revision C2.

The existing infrastructure (TAPS, Dalton Highway, fiber-optics line) within this corridor was built in the optimal location with respect to their routing criteria. The terrain and other routing criteria limit the ability of the Mainline to be within those existing ROWs. Placing a large-diameter, high-pressure pipeline at the edge of the Dalton Highway in a narrow mountain pass is impracticable from a construction and cost perspective. Although a large-diameter pipeline can be installed with a narrow ROW for a limited distance, it is not physically practicable to do so for long distances.

For example, TAPS and the Dalton Highway used routing that minimized side-slope crossings and steep grades, avoided geohazards where practicable, crossed rivers at locations with suitable flat benches on either side of the river, and minimized the turning radius of the pipeline or slope of the road. Project representatives are conducting a joint study with Alyeska Pipeline Service Company to assess the effect of the proposed Mainline on the TAPS and fuel gas pipeline. The fuel gas pipeline brings gas from the North Slope and is used by Alyeska to feed turbines in the pump stations along the TAPS. Generally, the pipeline runs parallel to TAPS, resulting in several instances where the Project proposes to cross this pipeline as well. As a starting point for the TAPS impact study, all locations, parallel encroachment and crossings, where the Mainline is within 200 feet of either the TAPS mainline or the fuel gas pipeline were identified. This distance was selected because it was used as minimum offset from the TAPS mainline, where feasible, when creating the Project's Route Revision C2. There are areas in which the Mainline comes within 200 feet of TAPS or the fuel gas pipeline. Site-specific investigations of each of these areas would be conducted prior to construction planning to ensure installation of the Mainline does not impact either TAPS or the fuel gas pipeline.

Considering there are few options in traversing north to south across central Alaska, the Mainline is within 1 mile of other existing linear ROWs for almost 75 percent of the route. The route generally follows TAPS, the Dalton Highway, the Parks Highway, Alaska Railroad, Beluga Highway, Kenai Spur Highway, and Intertie powerline ROWs, but is not placed within those existing ROWs because the routing criteria are not compatible with the routing of these existing ROWs. For instance, the Dalton and Parks highways cross

17 The DOI Public Land Order 5150 withdrew federal land specifically for a utility and transportation corridor. Public Land Order 5150 was enacted in 1971 and predates both the Toolik Research Natural Area and BLM ACECs. The Dalton Highway Master Plan also addresses land management issues within the Dalton Highway/Public Land Order 5150 corridor.

18 Alaska Senate Bill 70 provides a defined corridor through Denali State Park for the purpose of a natural gas pipeline.

major rivers at locations conducive for bridge construction (flat natural topographic benches on either side of the river). Because the Mainline would be buried (either by trenchless or open-cut method) across almost all river crossings, the Mainline would need to be separate from the existing road ROW to accommodate the large construction ROW needed to install the pipeline and not undermine the structure of the road bridge. The same can be said for not placing the Mainline in the existing TAPS ROW because about half of TAPS is above the ground or has aerial river crossings.

There is limited ability for placement of the Mainline directly abutting the existing infrastructure previously identified. To minimize environmental impacts and maintain the required engineering criteria, only short stretches of existing ROW are suitable for placing the Mainline ROW adjacent to these features. Many of the environmental features listed in the routing criteria are found along these existing ROWs. To avoid or minimize the impacts to those features, the Mainline was moved a farther distance away to avoid them (this was done repeatedly over hundreds of miles for wetlands, archaeological sites, waterbody crossings, Native allotments, etc.). In many cases (Alaska Railroad, highways), the existing ROW is in a river floodplain and there is little room on either side of the existing ROW to place a new utility because of the impacts that would occur to the river itself or to the many tributaries that feed into that river. It was less of an environmental impact to move the Mainline away from the existing linear feature to shorten the lengths of and number of crossings of the tributaries feeding into the river (this can be seen in reviewing the maps in Resource Report No. 1, Appendix A, from MPs 475 to 560 along the Nenana River and between MPs 650 and 735 along the Susitna River).

South of approximate MP 680, the Mainline route runs southwest to the north shore of Cook Inlet northeast of Viapan Lake, which is between the communities of Beluga and Tyonek. The offshore portion of the Mainline route crosses Cook Inlet to the Kenai Peninsula near Boulder Point. From the south shore of Cook Inlet near Boulder Point, the Mainline route continues south and west to the termination point at the proposed Liquefaction Facility (see Section 10.3.2 for Liquefaction Facility site selection). The location of the Liquefaction Facility restricts options for this portion of the Mainline route, and major alternatives for crossing Cook Inlet are provided in the following section.

A summary of the areas where the Mainline does not follow existing ROWs (within 1 mile as defined by the Project) is provided in Table 10.4.2-1. As indicated, the Project follows in the only corridors traversing Alaska from north to south for almost 74 percent of the distance from Prudhoe Bay to Nikiski.

TABLE 10.4.2-1

Locations Where the Mainline is Considered Greenfield[a]

Mainline MP		Length (miles)	Borough/ Census Area	Rationale
Start	End			
11.48	24.68	13.20	North Slope Borough	Separated from TAPS and the Dalton Highway as the pipeline is routed around several large lakes
60.41	61.88	1.47		Separated from TAPS and the Dalton Highway as the pipeline is routed around a large lake
97.32	100.13	2.81		Separated from TAPS and Dalton Highway based upon terrain where the large-diameter pipeline could not be placed within Atigun pass
130.41	135.17	4.77		Route is straightened to shorten the length of pipeline and associated impacts
404.72	465.75	61.02	Yukon-Koyukuk Census Area (to MP 421.87); Fairbanks North	Segment near Livengood where the route diverges from TAPS and proceeds southwest (toward Nikiski) prior to entering the Parks Highway corridor

TABLE 10.4.2-1

Locations Where the Mainline is Considered Greenfield[a]

Mainline MP		Length (miles)	Borough/ Census Area	Rationale
Start	End			
			Star Borough (to 424.31); Yukon-Koyukuk Census Area	
475.18	495.45	20.26	Yukon-Koyukuk Census Area (to 488.58); Denali Borough	Separated from the Parks Highway and Alaska Railroad as the pipeline is routed around the Lost Slough area
523.24	524.50	1.25	Denali Borough	Separated from the Parks Highway and Alaska Railroad, avoiding large wetland areas associated with Minto Flats and an area containing businesses and dwellings
527.04	527.91	0.87		Separated from Parks Highway as the pipeline is routed around Otto Lake
538.83	539.27	0.44		Part of the area where the route is located to avoid the DNPP boundary (diverging from the Parks Highway)
575.40	575.47	0.07	Matanuska-Susitna Borough	Small segment that does not meet the 1-mile criteria
583.34	585.35	2.01		Separated from the Parks Highway and Alaska Railroad as the Mainline is routed around multiple branches of Tsaani Creek
600.46	601.56	1.09		Separated from the Parks Highway as the pipeline is routed around portions of Honolulu Creek
641.96	645.92	3.96		Separated from the Parks Highway as the pipeline is routed around Chulitna River
675.75	766.04	90.29	Matanuska-Susitna Borough (to MP 755.33); Kenai Peninsula Borough	Separated from the Parks Highway as the pipeline is routed around the Susitna River, routed to stay on high ground and out of bog wetlands, and then proceeds southwest toward the proposed northern shoreline crossing (Shorty Creek) location of Cook Inlet
793.29	795.65	2.36		Proposed Cook Inlet southern shoreline crossing (Boulder Point) location onto the Kenai Peninsula
Total		205.88 miles (Approximately 26 percent of the onshore portion of the Mainline)		

[a] Mainline is located at least 1 mile (from the centerline) from existing ROWs. Existing infrastructure may consist of pipelines, major roads, railroads, and underground/aboveground utilities that are 2.5 miles or greater in length.

10.4.2.3 Mainline

The purpose of the Mainline is to transport gas from the control point of the GTP to the Liquefaction Facility. Initially a 2-mile-wide study corridor was established that followed the existing TAPS and Dalton Highway corridor from the Prudhoe Bay area south to Livengood. The proposed route also took the opportunity to align with existing transportation corridors south of Livengood (i.e., Parks Highway), as much as practical (see the prior collocation discussion), including utilization of the BLM-designated utility corridor for almost one-half of northern part of the route. After establishing a corridor that generally followed existing ROWs, a 2,000-foot-wide corridor was identified using preliminary data from existing literature and field reconnaissance. The routing criteria and routing considerations are discussed in the previous sections. To the extent practicable, the Project used the routing criteria as outlined previously when determining a route within the 2,000-foot-wide corridor. However, in some cases, avoiding conservation lands, or NRHP-eligible archaeological sites, pushed the route into wetlands or away from collocation opportunities. The Applicant balanced the engineering, construction, environmental, regulatory, social, and cost implications of each routing decision.

Major and minor route alternatives for the Mainline are described in Sections 10.4.3 and 10.4.4, respectively. A discussion of the routing efforts undertaken for the other pipeline components of the Project are discussed in the following sections.

10.4.2.4 Point Thomson Gas Transmission Line (PTTL)

Because the PTTL would be built above ground on VSMs, the routing efforts were concentrated on paralleling existing aboveground pipeline infrastructure and identifying the shortest route possible to avoid impacts to wetlands and perennial streams. None of the existing VSMs supporting other pipelines were designed to accommodate an additional large-diameter pipeline.

After the decision was made to install the PTTL above ground (See section 10.4.5.1.2), routing focused on the shortest length while collocating with existing pipelines and ensuring the larger waterbody crossings were sited to cross at the narrowest portion of the river and at a perpendicular angle.

The routing for Revision B, filed in the June 14, 2016 draft application for the Project, resulted in the PTTL paralleling the Point Thomson Export Pipeline (liquids) (also above ground on VSMs) and Badami Sales Oil Pipeline (also on VSMs) for the majority of the first approximate 49 miles of the total 62.5 miles. For the majority of the remainder of the route, the PTTL would parallel the Endicott Pipeline and other existing pipe racks within the PBU. Routing for Revision B resulted in improvements to the crossing angle of major rivers, avoided pingos (mounds of earth-covered ice found in Arctic and Subarctic regions), and provided greater separation from existing drill pads and production facilities. Because the proposed route is the shortest option from PTU to the GTP, and minimizes impacts to wetlands by being installed above ground in the winter, no major or minor route alternatives were identified for the PTTL. However, proposed Route Revision C incorporates an increased offset of the PTTL from the Point Thomson Export Pipeline to allow additional room for pipeline construction. The offset for Route Revision C is 0.01 mile longer and results in an additional road crossing and three additional non-anadromous stream crossings. Proposed Route Revision C of the PTTL is shown in Resource Report No. 1, Appendix A. The PTTL would be built using ice roads and ice pads for construction of aboveground pipelines and support systems, so wetland impacts would be reduced compared to a belowground installation.

Additional details concerning selection of an aboveground versus belowground mode for the PTTL are provided in Section 10.4.5.1.2.

10.4.2.5 PBU Gas Transmission Line (PBTL)

The proposed PBTL would be elevated on VSMs from the GTP to the PBU Central Gas Facility (CGF). The route is approximately 1 mile. The entire area is wetland and, with ponds to the northwest that would need to be avoided, there were no other alternatives to study to traverse the short distance between the GTP and the PBU CGF. Impacts would be minimized by installing the PBTL in the winter from ice roads on VSMs.

10.4.3 Major Route Alternatives

Major route alternatives for the proposed Mainline are discussed in the following section.

10.4.3.1 Onshore Pipeline

10.4.3.1.1 Straight Line (Shortest Distance) Route Alternative

An alternative to the Mainline was evaluated that would route the pipeline in a straight line directly from the GTP to the proposed Liquefaction Facility in Cook Inlet. The Straight Line Route Alternative is shorter than the proposed Mainline, and it consequently would require less pipeline to construct and less permanent pipeline ROW to maintain. However, following preliminary investigation, the Straight Line Route Alternative poses multiple noteworthy construction, environmental, and commercial challenges that make it an impractical and infeasible alternative despite its shorter length. For example, the Straight Line Route Alternative would cross through the Gates of the Arctic NPP in the heart of the Brooks mountain range, the Kanuti NWR, the Yukon Flats NWR, the DNPP in the wilderness area in the Alaska mountain range, and through the Ray mountains. All of these crossings would create a new corridor through these conservation lands. Crossing NWRs requires a compatibility analysis that would require documentation that there are no feasible alternatives to crossing the NWR, which in this case is not feasible because the Applicants' proposed alternative would avoid them all. The Straight Line Alternative would cross the Tanana and Yukon rivers in undeveloped areas, requiring extensive road support to be built from the existing highway system into undeveloped areas. Crossing through the three mountain ranges would open a new corridor through undeveloped areas of Alaska that would be difficult to support during construction and operations without a permanent road base built concurrently with the buried pipeline. Constructing through these three mountain ranges would be cost prohibitive (impracticable) without first developing an access road through these areas. The combination of these considerations would result in a cost-prohibitive alternative to the Applicants' proposed alternative. Therefore, this alternative was eliminated from further consideration.

10.4.3.1.2 Valdez Delivery Option

The TAGS delivery option does not meet the purpose of the Mainline to transport gas from the control point of the GTP to the Liquefaction Facility at Cook Inlet. Although the TAGS (and to some degree, the TAPS route that is followed by TAGS) was studied in the 1988 FEIS produced by BLM and USACE and the 1995 FERC EIS, and deemed to be an environmentally acceptable alternative to a route to Cook Inlet, there have been some changes to conservation designations along the Valdez delivery option route that have occurred since the TAGS FEIS was produced and all of the environmental data would need to be re-collected and remapped (survey protocols have changed since the original data was collected). Portions of two Wild and Scenic River corridors, withdrawn for those purposes under ANILCA, are traversed by the Valdez Delivery Option (TAGS). The Gulkana River, crossed by a Valdez delivery option, and the Delta River, paralleled by a Valdez delivery option, would have to be avoided or require NPS/Congressional/Presidential approval to cross it. For both rivers, there are no feasible options to avoiding the river (note: even a trenchless or aerial crossing still requires an easement across the NP designation, and the NPS is not authorized by Congress to issue any such easement without Congressional and Presidential approval). A basic routing constraint for most pipeline projects, this is an exclusion factor with the routing of the delivery option for the Anderson Bay facility site.

The pipeline also has to traverse terrain steeper than on the Nikiski delivery option routing. Through Thompson Pass, the pipeline would traverse over 4.3 miles of steep slope areas (>20 percent grade) trying to follow the TAPS alignment and Richardson Highway. As shown in the following sections, there are many locations where additional space is unavailable, making this routing technically infeasible without creating a new ROW down the mountain pass.

This corridor is the only existing access corridor from Valdez to other areas of the state (BLM and USACE, 1988), which is already constrained with the placement of the Richardson Highway and TAPS. The joint study conducted by TAPS and Alaska LNG indicated that long stretches of the Alaska LNG pipeline within the TAPS ROW (or even adjacent) would not be physically feasible to ensure the safe operations of both systems. This would preclude use of the previously studied corridor, requiring additional detailed engineering and studies to find suitable routes across the mountain passes to Valdez. TAGS routing was conceptual at the completion of the FEIS, and a long list of requirements was required by the BLM and USACE before final approval of the route, including detailed plans on how the pipeline would be placed through these two space-constrained features. A new route would need to be prepared, with the possibility of tunneling or benching large areas of rock to prepare a safe and level location to put the pipeline. The ADOT&PF has expressed past concerns about the potential impact of pipeline construction or operations should a landslide occur, closing this pinch point (BLM and USACE, 1988). Keystone Canyon is a 2.6-mile-long, deep gorge of the Lowe River that has the same constraints with workspace as well as landslide risk (BLM and USACE, 1988). In 2014, a significant landslide occurred in the Canyon. The landslide resulted in the closing of Richardson Highway, the only road into Valdez, for almost two weeks. The technical challenges to build a pipeline in a new corridor across these two features would add risk to the Project schedule and costs because of the need to find and build through a new area with steep terrain and unstable soils.

Besides the exclusion factor of crossing the Wild and Scenic River, the pipeline route would also have to cross through a National Forest. This action would trigger additional approval necessity above the local National Forest managers to Washington D.C.

A comparison of the Valdez Delivery Option versus the proposed Mainline route from Livengood to Nikiski is provided in Table 10.4.3-1. The comparison includes criteria such as pipeline length, amount of wetlands and number of waterbodies, acres of each category of land cover, number of cultural resources, land ownership, special use areas, nearby communities, and additional special pipeline construction concerns. To analyze reasonably foreseeable routes that would allow for in-state gas deliveries to major population centers, spur lines to benefit in-state gas users were also included in the analysis. For the proposed Mainline route from Livengood to Nikiski, a spur to Fairbanks was included based on the ASAP Project's Fairbanks Lateral route. For the alternative Valdez Delivery Option from Livengood to Valdez, a spur to Palmer from Glennallen was incorporated based on the Alaska Natural Gas Development Authority (ANGDA) spur route. The portion of the pipeline from the North Slope to Livengood would remain unchanged, so it is excluded from the comparison. An overview of the routes is provided in Figure 10.4.3-1.

TABLE 10.4.3-1

Comparison of Route Alternatives

Criteria	Proposed Mainline from Livengood to Nikiski with a Spur to Fairbanks	Alternative Mainline from Livengood to Valdez with a Spur to Palmer
Pipeline length	Proposed Mainline - Approx. 403 miles long Fairbanks Spur – Approx. 30 miles long	Alternative Mainline - Approx. 406 miles long Palmer Spur – Approx. 148 miles
Wetlands[a]	Approx. 673 acres freshwater wetland and riverine impacts (permanent)[f] Approx. 174 acres marine and estuarine wetland impacts (permanent)[f]	Approx. 851 acres freshwater and riverine wetland impacts (permanent)[g,h]
Waterbodies[b]	175 rivers and streams to be crossed, including 86 anadromous streams	314 rivers and streams to be crossed, including 80 anadromous streams

TABLE 10.4.3-1

Comparison of Route Alternatives

Criteria	Proposed Mainline from Livengood to Nikiski with a Spur to Fairbanks	Alternative Mainline from Livengood to Valdez with a Spur to Palmer
Land Cover[c]	Approx. 1,858 acres of forest, 723 acres of open land, 183 acres of open water, 36 acres of residential land, and 2 acres of agricultural land[f]	Approx. 2,261 acres of forest, 1,049 acres of open land, 13 acres of open water, 232 acres of residential land, 11 acres of agricultural land, and 1 acre of commercial/industrial land[g]
Cultural Resources[d]	67 documented cultural resources. 24 have been determined eligible for listing in the NHRP, 21 determined not eligible for listing, and remaining 21 have not yet been evaluated for NRHP eligibility, 1 pending NRHP eligibility concurrence from SHPO[i]	43 documented cultural resources. 2 have been determined eligible for listing in the NHRP, 3 determined not eligible for listing, and remaining 37 have not yet been evaluated for NRHP eligibility, 1 pending NRHP eligibility concurrence from SHPO[i]
Land ownership[e]	Crosses federal and state owned and managed lands, Native Corporation land, and private land Approx. 78.1% of Mainline route traverses State of Alaska land, 0.2% crosses BLM-managed land	Crosses federal and state owned and managed lands, Native Corporation land, and private land Crosses military land Approx. 51.2% of alternative Mainline traverses State of Alaska land, 20.2% crosses BLM-managed land
Recreation and Special Use Areas	Denali National Park nearby Route crosses Iditarod National Historic Trail, 0 ACECs, Denali State Park, Nenana River Gorge Special Use Area, Alexander Creek State Recreation River, Kroto Creek and Moose Creek SRRs, Susitna Flats SGR, Tanana Valley State Forest, Minto Flats SGR, 1 scenic byway	Route crosses Delta River and Gulkana River Wild and Scenic River Corridor Withdrawals Route crosses 0 ACECs, Blueberry Lake State Recreation Site, Chugach National Forest, Palmer Flats SGR, Thompson Pass SGR, Worthington Glacier State Recreation Site, 2 scenic byways
Nearby Communities	Fairbanks, Nenana, Healy, McKinley Park, Cantwell, Trapper Creek, Talkeetna, Willow, Houston, Beluga, Nikiski	Fox, Fairbanks, North Pole, Salcha, Big Delta, Delta Junction, Paxson, Gakona, Gulkana, Glennallen, Tazlina, Copper Center, Kenny Lake, Tonsina, Valdez, Eureka, Chickaloon, Jonesville, Sutton, Palmer
Special Pipeline Construction Consideration	Lynx Creek Crossing Uses existing rail system between Fairbanks and southcentral Alaska Subsea pipeline in Cook Inlet, requires mitigation for potential shipping conflicts and marine mammal impacts	Thompson Pass Routing Limited rail system use (between Fairbanks and North Pole only), resulting in - more truck traffic on Richardson Highway - more impacts from fugitive dust and truck emissions - more traffic, health, and safety mitigation

TABLE 10.4.3-1

Comparison of Route Alternatives

Criteria	Proposed Mainline from Livengood to Nikiski with a Spur to Fairbanks	Alternative Mainline from Livengood to Valdez with a Spur to Palmer

[a]Based on NWI data.

[b]Based on National Hydrography Dataset.

[c]Based on National Land Cover Database data.

[d]Based on Alaska Heritage Resources Survey data.

[e]Derived from BLM's online Generalized Land Status of Alaska (GLS).

[f]Calculated using a 51-foot corridor for the Fairbanks spur (12-inch diameter pipeline) and 53.5-foot corridor for the Mainline from Livengood to Nikiski.

[g]Calculated using 52-foot corridor for the Palmer spur (24-inch diameter pipeline) and 53.5-foot corridor for the Mainline from Livengood to Valdez.

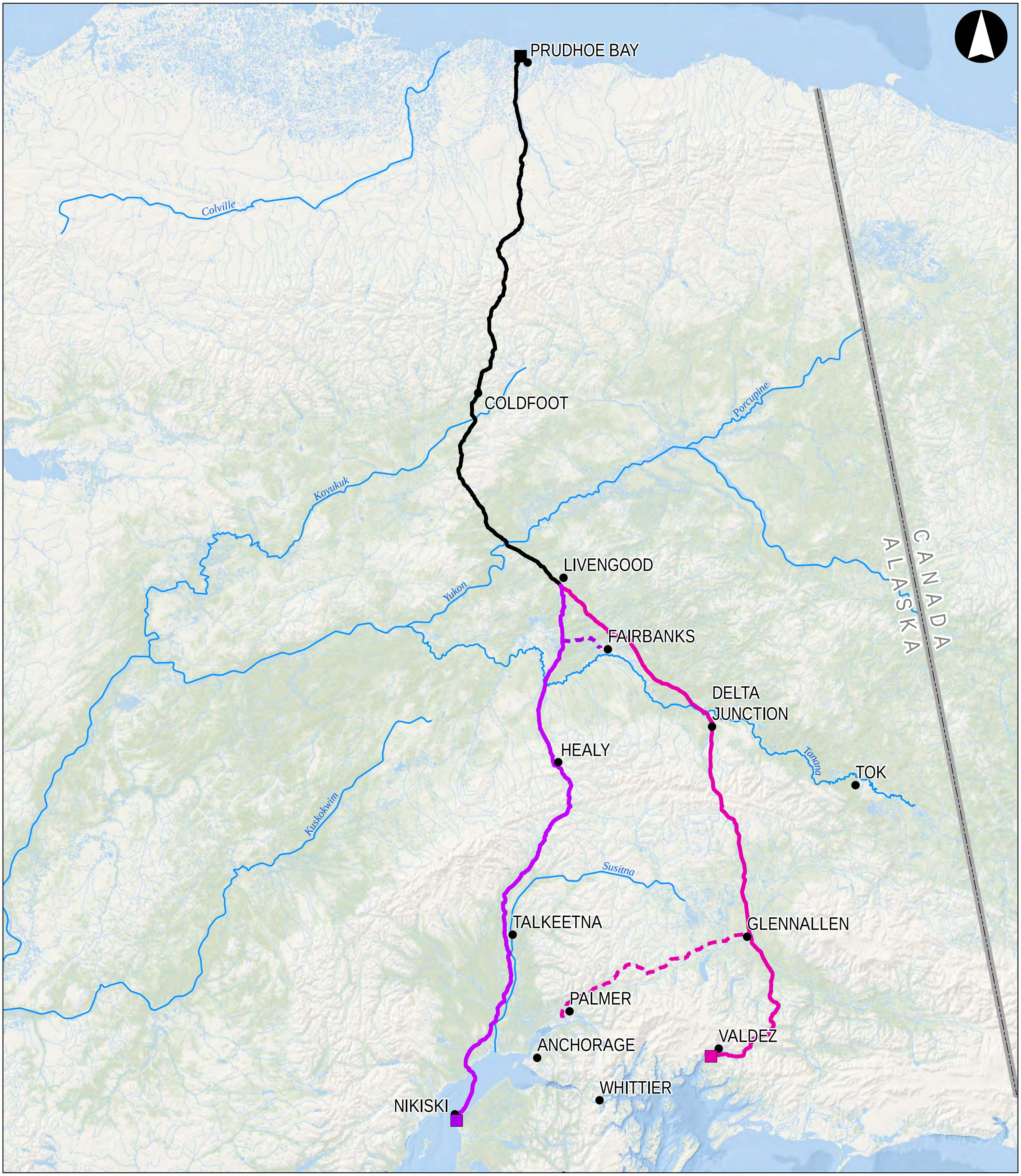
[h]NWI data is unavailable for approximately 9 miles of Palmer spur route.

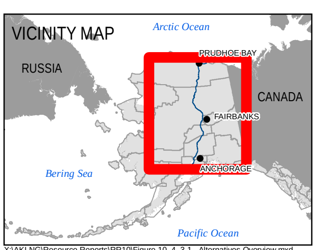
[i]Analysis Area included a 300-foot corridor for each Mainline route and spur.

For the purpose of consideration of impacts and effects to cultural resources, records in the Alaska Heritage Resources Survey (AHRS) were reviewed to determine the presence/absence of cultural resources and the level of survey generally completed within and along the Valdez Delivery Option for comparison with the proposed Mainline. The review included all areas that may be impacted during construction or operation of the Valdez Delivery Option (Analysis Area). Specifically, the Analysis Area included a 300-foot-wide corridor centered on the each mainline and spur line route.

Examination of AHRS records revealed a total of 110 documented cultural resources located within the Analysis Area. Of these cultural resources, 26 have been determined eligible for listing in the NRHP and are therefore considered historic properties for the purpose of consultation under Section 106 of the NHPA, 24 have been determined not eligible for listing in the NRHP and therefore do not require further consideration under Section 106, and the remaining 58 have not yet been evaluated for NRHP eligibility. Historic Properties within the Analysis Area include both surficial and buried prehistoric sites, historic and multicomponent sites including log cabins, culturally modified trees, and surface depressions; and historic trails, including trails associated with the Historic Iditarod Trail. Unevaluated cultural resources include prehistoric lithic sites; historic trails, roads, bridges and cabins; surface depressions such as cache pits and more. It is important to reiterate that while only effects to historic properties (those cultural resources determined eligible for listing in the NRHP) are considered under Section 106, all cultural resources are considered for impacts under the NEPA. Additionally, it is important to note that a sizeable portion of the Analysis Area has not been surveyed for cultural resources and prior work completed for the Valdez corridor would need to be re-surveyed using current approved methodologies.

Table 10.4.3-2 compares land ownership information for the proposed and alternative mainline routes with respective spur lines.





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LEGEND

- GTP Facility
- Liquefaction Facility
- Anderson Bay Port
- Alaska LNG Rev C2 Route
- Proposed Mainline
- Reasonably Foreseeable Spur Line (ASAP)
- Alternative Mainline (Valdez Delivery Option)
- Reasonably Foreseeable Spur Line (ANGDA)

0 10 20 40 60 Miles

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OVERVIEW OF PROPOSED MAINLINE ROUTE AND ALTERNATIVE VALDEZ DELIVERY OPTION

FIGURE 10.4.3-1

ALASKA LNG

TABLE 10.4.3-2

Land Ownership Comparison

Generalized Land Status	Length (Miles)	% of Length	Generalized Land Status	Length (Miles)	% of Length
Proposed Mainline - Livengood to Nikiski			**Alternative Mainline - Livengood to Valdez**		
BLM	0.79	0.2%	BLM	81.86	20.2%
Native Patent or Interim Conveyance[a]	52.54	13.0%	Military	38.12	9.4%
Native Selected[a]	8.13	2.0%	Native Patent or Interim Conveyance[a]	55.82	13.8%
State Patent or Tentative Approval to Patent	314.66	78.1%	Native Selected[a]	3.61	0.9%
Water	26.77	6.6%	Private	15.61	3.9%
Total	**402.89**		State Patent or Tentative Approval to Patent	207.57	51.2%
			State Selected	2.79	0.7%
			Water	0.08	0.0%
			Total	**405.45**	
Fairbanks Spur			**Palmer Spur**		
Military	2.11	6.9%	Native Patent or Interim Conveyance[a]	18.19	12.3%
Private	0.41	1.4%	Native Selected[a]	3.94	2.7%
State Patent or Tentative Approval to Patent	27.80	91.7%	Private	6.36	4.3%
Total	**30.32**		State Patent or Tentative Approval to Patent	118.27	80.0%
			State Selected	1.17	0.8%
			Total	**147.93**	
[a]Alaska Native Corporations formed under ANCSA					

Approximately 78.1 percent of the proposed Mainline route centerline traverses State of Alaska land whereas approximately 51.2 percent of the alternative Valdez Delivery Option mainline centerline traverses State land. The Valdez Delivery Option Route therefore impacts approximately 27 percent more non-State landowner entities than does the proposed Mainline route. Whereas approximately 9.4 percent of the Valdez Delivery Option route south of Livengood traverses Military land, none of the proposed Mainline route traverses Military land. Approximately 21.8 percent of the alternative Valdez Delivery Option from Livengood south traverses BLM-managed land (20.2 percent BLM, 0.9 percent Native Selected, 0.7 percent State Selected) whereas only approximately 2.2 percent of the proposed Mainline from Livengood south traverses BLM-managed land (0.2 percent BLM, 2.0 precent Native Selected). Three point nine percent of the Valdez Delivery Option traverses private land whereas GLS reports that no private lands are traversed by the proposed Mainline route.[19]

[19] The Alaska LNG's detailed land status data base does show that some private lands are traversed south of Livengood.

Approximately 91.7 percent of the Fairbanks spur centerline traverses State of Alaska land whereas 80.0 percent of the Palmer spur crosses State land. BLM's online Generalized Land Status of Alaska (GLS) reports that 6.36 linear miles or 4.3 percent of the total Palmer spur distance crosses private land whereas 0.41 linear miles or 1.4 percent of the Fairbanks spur traverses private land. The Palmer spur crosses 18.19 linear miles of Native-owned land or 12.3 percent of the total Palmer spur distance whereas the Fairbanks spur crosses no Native-owned lands. The Palmer spur also crosses 3.94 linear miles of Native Selected land whereas the Fairbanks spur crosses no Native Selected land. GLS reports that the Fairbanks spur crosses 2.11 miles of Military land.[20]

10.4.3.1.3 Mainline Route Revision C2 (Proposed Alternative)

In February 2015, the Applicant filed under FERC Docket No. PF14-21-000 an approximate 2,000-foot-wide study corridor for the Mainline from Prudhoe Bay to Nikiski. That study corridor is referred to as Route Revision A (the centerline of that study corridor). As part of that filing, the Applicant noted that within the Route Revision A study corridor, a preliminary route (Route Revision B) would be identified based on agency discussions, field surveys, community meetings, and engineering (within the Revision A study corridor). Route Revision B of the Mainline, provided in the June 14, 2016 draft application, reflected the results of that route identification process.

Part of the identification of Route Revision B was to work with the ASAP Project to produce a common alignment for the northern 680 miles of the approximate 807-mile route. A common alignment was facilitated at the request of the State of Alaska to minimize agency review and leverage the experience of both projects to develop an optimal route. As part of that effort, the Project's Route Revision A corridor centerline and the ASAP Version 5 route were compared to determine the most advantageous segments of each to form a common alignment. Multidisciplinary teams from both projects met to complete this review. The evaluation team also created new route alignments where the review process identified better route options that neither route provided. In total, there were 34 route changes created as a result of the work done by both projects between Route Revision A and Revision B. These minor route variations are discussed further in Section 10.4.4.3.

As noted above, the Applicant has made further revisions to the Mainline to develop the proposed Route Revision C2. Route Revision C2 takes into consideration agency and scoping comments on the Rev B centerline, as well as identifies opportunities to further optimize the route. These minor route variations are discussed further in Section 10.4.4.3. Proposed Route Revision C2 of the Mainline is shown in Resource Report No. 1, Appendix A.

10.4.3.2 Cook Inlet Alternatives

Alternative routes for the Mainline were evaluated as it approached Cook Inlet, crossed Cook Inlet, and then connected with the Liquefaction Facility at Nikiski, along the final 100 miles of the pipeline route. Cook Inlet is a challenging environment for design and installation of pipelines. However, there have been a number of small pipelines built across Cook Inlet since oil and gas development started there in the 1960s. One of the most challenging aspects of routing across Cook Inlet is selecting a suitable shore crossing location for both the northern and southern coastlines. Steep cliffs and slopes, large boulders, land ownership issues, distance to deep water, and offshore constraints (both natural and manmade) required consideration during selection of the proposed shore crossing location. Pipeline construction alternatives

[20] ASAP's detailed land status indicates that no Military lands are crossed by the Fairbanks spur, although the alignment is proximate to Military lands.

across Cook Inlet are provided in Section 10.6.3. With the anticipated lay vessels capable of holding station in Cook Inlet having minimum drafts of 20 feet, it was important to find crossing locations where the lay vessel can approach as close to shore as possible that the vessel can pick up the pipe and initiate the offshore lay. Therefore, the constructability of shoreline approaches on both the northern and southern shoreline of Cook Inlet was evaluated as part of the analysis of selecting a proposed route across the Inlet (see the subsequent shore crossing discussion).

Three alternative routes were evaluated (see Figure 10.4.3-2) that examined different approaches to Cook Inlet:

- East Route Alternative – The East Route Alternative lies west of the Susitna River near the Deshka River then proceeds south-southeast to cross the Big Susitna and Little Susitna rivers, crossing on the north shore of Cook Inlet in the Point MacKenzie area. The East Route alternative crosses the Cook Inlet initially north and then west of Fire Island, crossing the southern shore of Cook Inlet near Miller Creek. The route then follows the shoreline south-southwesterly to Nikiski.

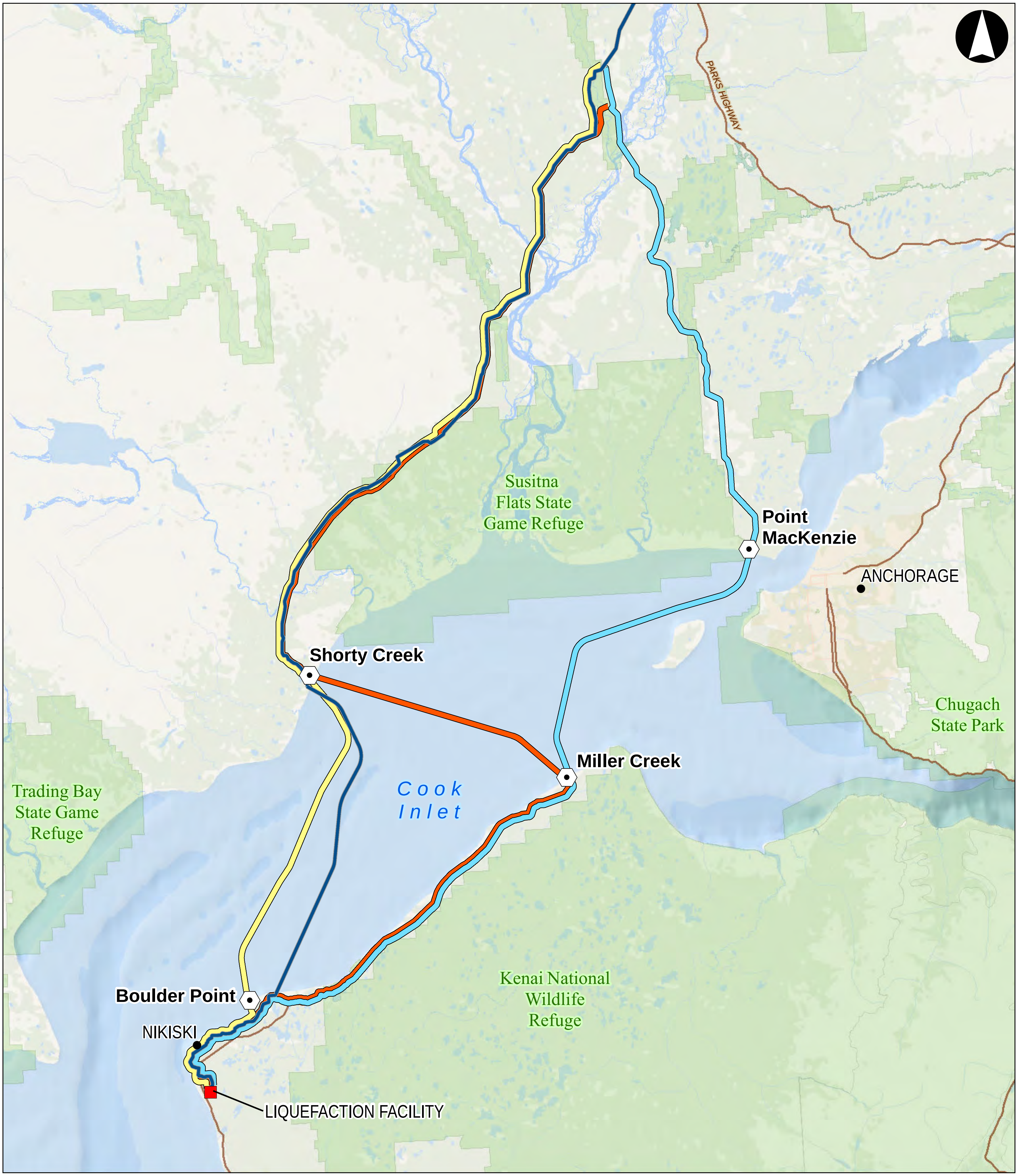
- West Route Alternative – The West Route Alternative stays west of the Susitna River and proceeds south-southwesterly, crossing on the north shore of Cook Inlet in the Beluga area. The offshore portion of this alternative crosses Cook Inlet to the Kenai Peninsula near Boulder Point. From the south shore of Cook Inlet near Boulder Point, the West Route Alternative continues south and west to Nikiski.

- West-East Route Alternative – The West-East Route Alternative parallels the West Corridor until it crosses Cook Inlet. This alternative crosses Cook Inlet, crosses the south shore of Cook Inlet in the Miller Creek area, and then parallels the East Route Alternative, essentially creating an excessively long zigzag route across Cook Inlet and on the Kenai Peninsula.

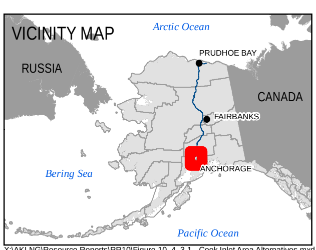
The West-East Route Alternative was dropped from further consideration during this analysis. It became obvious that not only was this alternative longer (approximately 12 to 26 miles), but it would require crossing cables in Cook Inlet and require pipe lay at a shallow angle to the bidirectional current in Cook Inlet thereby exposing the longer side of the lay barge to high currents. This would require additional tugs and barges to maintain station during pipe lay, and would keep construction for a longer period of time in Cook Inlet, leading to greater potential conflicts with Cook Inlet beluga whales. A comparison of the West versus East Route Alternatives is provided in Table 10.4.3-3.

As shown on Figure 10.4.3-3, four crossing locations were considered for the Mainline crossing of Cook Inlet: Shorty Creek, Point MacKenzie, Miller Creek, and Boulder Point. The Applicants' proposed alternative is Shorty Creek and Boulder Point for the West route. Each are described in the following paragraphs.

- Shorty Creek (North Shore Crossing, West Route) – The Shorty Creek shore crossing begins at approximately 90 feet in elevation as it descends a steep bluff (0.3 mile) to the shoreline. The route then crosses gently sloping intertidal mudflat. The route remains straight for approximately 2.1 miles once it leaves the shoreline. The gentle slope of the mud flats makes the location suitable for open-cut, microtunnel, and horizontal directional drill (HDD) crossing method options. The Shorty Creek shore has a low risk of large boulders or sand waves offshore (sand waves would result in the pipeline spanning or laying off the bottom between sand waves).



VICINITY MAP



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LEGEND

- Alaska Place Names
- Project Facility
- Major Highways
- Alaska LNG Rev C2 Route
- Rev B West Route
- Rev B East Route
- Rev B West-East Route
- State and Federal Conservation Lands

0 2.5 5 10 15 Miles

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COOK INLET AREA ALTERNATIVES

FIGURE 10.4.3-2

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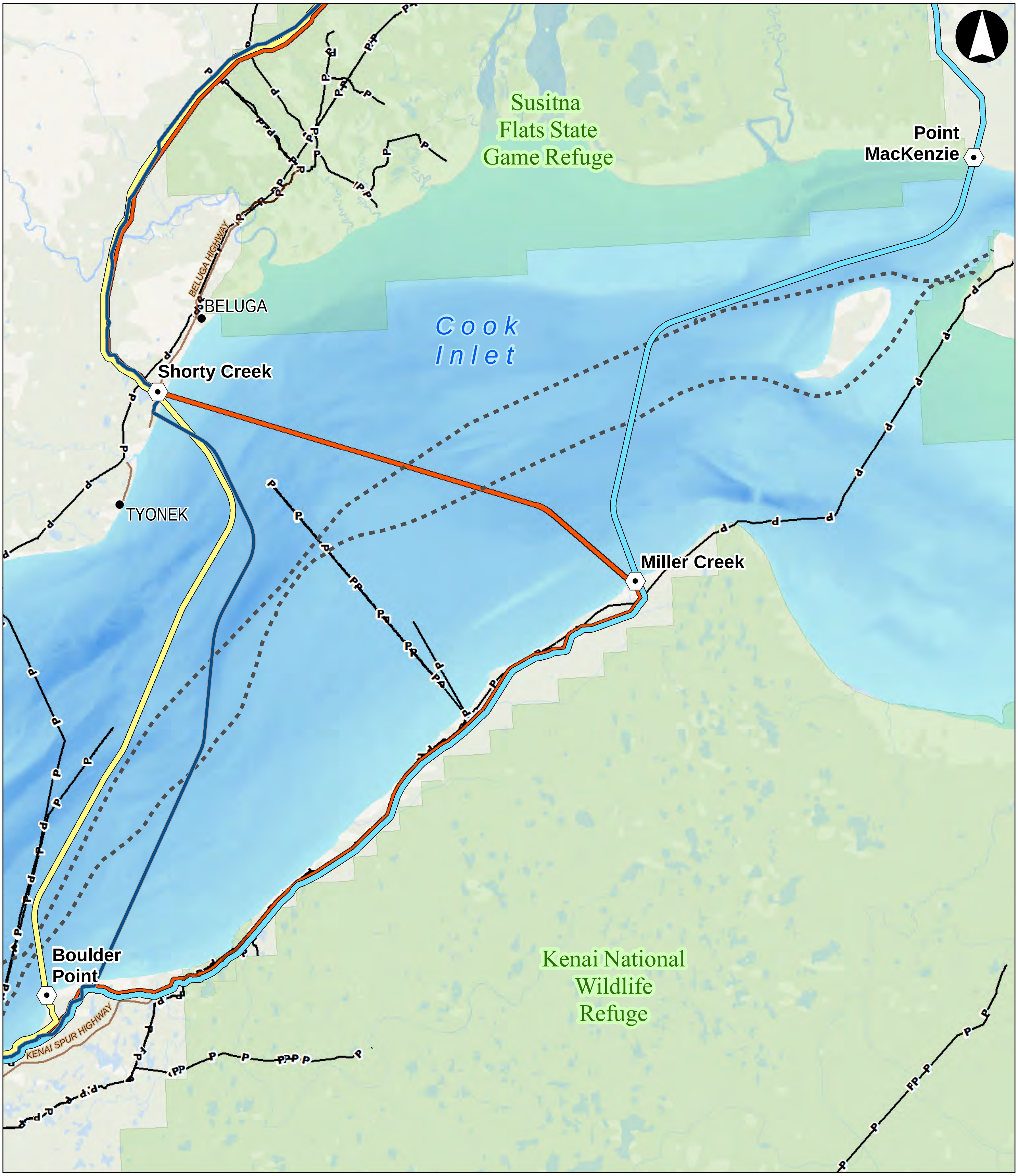

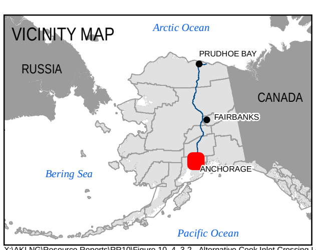

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LEGEND

- Alaska Place Names
- Crossing Point
- Alaska LNG Rev C2 Route
- Rev B West Route
- Rev B East Route
- Rev B West-East Route
- Major Highways
- Sub-Marine Telecom Cable
- P Existing Pipelines
- State and Federal Conservation Lands

0 2 4 8 Miles

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ALTERNATIVE COOK INLET CROSSING LOCATIONS

FIGURE 10.4.3-3

ALASKA LNG

- Point MacKenzie (North Shore Crossing, East Route) –The Point MacKenzie route begins on a mudflat at an elevation of approximately 28.5 feet. From northeast to southwest, it crosses a small embankment (an 8-foot drop) and two small scarps near the shoreline. The route remains straight for approximately 1.5 miles and is relatively flat, with some localized drainage channels. As the route exits Point MacKenzie, it is bound to the south by the ship canal, Woronzof Shoal, and Fire Island, and to the northwest by the North Point Shoal. Some issues related to constructability have been identified with this shore crossing location and transiting of Cook Inlet from this location. Chugach Electric Association has a wide power cable easement that contains eight major power cables that supply power to Anchorage just east of the shore crossing. Based on available public information, these cables cover the majority of the area within the easement. Because a lay barge uses 8 to 12 anchors (1,000 to 5,000 feet from the barge, depending on water depth and currents) to hold station during construction, the lay barge would be prohibited from laying its anchors inside the easement and the easement owners would probably also require a buffer zone around their easement to make sure no anchors would damage its cables.

  The presence of extensive shallow shoals, long mud flats (from 4,000 feet to 7,700 feet to the east and west of the route), and the Susitna Flats Game Refuge (to the west) prevents the route from moving farther west to avoid the power cable easement. A lay barge could not get to within 3,000 feet of the shore to facilitate pipe lay operations in Cook Inlet. There are extremely strong currents in the Point MacKenzie shore approach would run into the side of the lay barge with each tide. A considerable number of anchors and/or tugs under power would be required to hold the lay barge in place as the pipe is laid. These constraints restrict the access of a lay barge and anchor spread for this shore approach. The water depths are also too shallow to use a dynamically positioned vessel, which would also need to be augmented by anchors and/or tugs to hold the barge on station.

- Miller Creek (South Shore Crossing, East Route) – As the route crosses the shoreline from Cook Inlet, it remains straight for approximately 2.9 miles. The route then crosses a zone of sand waves perpendicular to the route and a zone of irregular seafloor laden with boulders on and below the seabed. After crossing the shoreline, the route crosses a steep bluff (approximately 82 feet) to an elevation of approximately 100 feet. The Miller Creek approach has generally low slopes to the shoreline and the location is suitable for micro-tunneling (direct pipe), open-cut trench, or an HDD. Water depths and seabed morphology would also accommodate a tie-in at this location.

- Boulder Point (South Shore Crossing, West Route) – As the route crosses the shoreline from Cook Inlet, it crosses a zone of irregular seafloor and a potential boulder field. The route crosses a steep (120-150 feet) bluff. Some issues associated with constructability were identified during the review of this crossing location. The presence of large boulders (some the size of homes) could make it difficult to trench or use a trenchless method through the area. Blasting and an open-cut construction method may be required to cross this shoreline. If an open-cut trenching operation is selected, breakwaters or cofferdams could be required. Not far offshore, the route would cross the Alaska-Oregon Network and Kodiak Kenai Fiber Link cables.

Based on the criteria summarized in Table 10.4.3-3, both the East and West Route alternatives are potentially viable. However, the West Alternative, with shore crossings near Shorty Creek and Boulder Point, is considered to be the Applicant's proposed alternative.

An optimal route was selected for proposed Route Revision C2 that takes into consideration updated regional datasets, as well as optimizes the required footprint (i.e., minimize impacts to sensitive resources, required pipeline length), design challenges (e.g., sea floor bathymetry, bluff height), and construction risks, such as those associated with currents and subsea geology (e.g., soils, boulders, faults). Route Revision C2 includes a minor route variation to Route Revision B (see Table 10.4.3-3 and Section 10.4.4.3), making adjustments to improve the shoreline crossings locations and onshore pipeline routing required to match the revised shoreline crossing locations (Figure 10.4.3-3). The bluff near the revised Route Revision C2 shoreline crossing location in the Shorty Creek area (also referred to as Beluga Landing South) is not as steep as the Route Revision B location. In addition, the revised Route Revision C2 shoreline crossing location in the Boulder Point area (also referred to as Suneva Lake) has a long shallow mud flat and less potential for encountering boulders than the Route Revision B location.

From an offshore design and construction perspective, the proposed West Route is strongly favored given the considerations associated with making the shore crossing at Point Mackenzie on the East Route. Reasons that the East Route is considered challenging are: 1) the crossing would require excavating across a wide shallow mud flat (up to 4,000 feet) to reach suitable depth for a lay barge to be able to reach and pick up the shore crossing to continue pipe lay in Cook Inlet; 2) the Chugach easement directly to the east of the route, coupled with the anchor spread requirement to lay anchors up to 5,000 feet from the barge would result in unresolvable conflicts on easement impacts; 3) strong cross and head-on/stern currents (depending on where along the route the lay barge is) would require that the lay barge be reinforced with tugs or additional anchors, or, conversely, not laid during peak tidal currents, prolonging construction; 4) daily construction activities in beluga whale CHA 1 would be constrained due to the high likelihood of beluga sightings near the barge; 5) almost half of the route crosses sand waves; these areas are highly unstable and increase the installation and operating risks, and 6) just offshore of the mud flats the bathymetry drops off into the Cook Inlet navigation channel. This would require the route to be diverted to the west to avoid the channel. Additional disadvantages of the East Route are that the route is longer; it impacts three fishery leases; it impacts a considerably greater number of private parcels, most of which are recreational or seasonal residences used for fishing and hunting in the Susitna River valley; and there is a higher number of known archaeological onshore sites along the route.

In contrast, the West Route alternative is more favorable for pipe lay because: 1) the route would be laid in the same direction as the main current channels in Cook Inlet, making it considerably easier and faster to lay pipe; 2) the west route is about 14 miles shorter; 3) the route has fewer known cultural resource sites; and 4) would be installed in Beluga Whale CHA 2, with fewer Cook Inlet beluga whale potential conflicts than in Beluga Whale CHA 1.

The Applicant has designated the West Route as the proposed alternative as a portion of the Revision C2 Mainline. In comparison to the West Route, the East Route Option:

- Is approximately 13.55 miles longer in total length (onshore and offshore);
- Is approximately 1 mile longer within Cook Inlet; and
- Is relatively closer to the Chu'itna Archaeological District.

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

Criteria			Alternative: West Route – Applicants' Proposed Alternative – Route Revision C2	Alternative: West Route – Route Revision B	Alternative: East Route
Engineering/Technical Considerations	Pipeline Length (miles)	Total	100.48	100.30	114.03
		Offshore	26.81	28.45	27.83
	Collocation within 500 feet of the centerline (miles)	Roadways	4.21	3.23	13.05
		Pipelines	2.27	2.25	19.67
		Powerlines	0.88	0.00	0.10
	Depth Range (feet)		0-130	0-140	0–89
	Seafloor Characteristics	Changes in Seabed Bathymetry	No significant changes noted in the seafloor between recent surveys (National Oceanic Atmospheric Administration [NOAA], 2008 and Fugro, 2014)	No significant changes noted in the seafloor between recent surveys (National Oceanic Atmospheric Administration [NOAA], 2008 and Fugro, 2014)	Changes noted in the seafloor between recent surveys (NOAA, 2008 and Fugro, 2014); historical seabed data along the east route suggest that seabed changes on the order of 30-40 feet may occur over a time scale of a few years or less.
		Approximate slopes (maximum offshore gradient, based on 10-foot spacing)	45 degrees	45 degrees	27 degrees
		Vessel Traffic Crossings	3	3	2
		Sand Waves	1.47 miles of the route is interpreted to be located in sand wave zones.	0.1 mile of the route is interpreted to be located in sand wave zones.	14.1 miles of the route are interpreted to be located in sand wave zones.
		Boulders	There are no known trenching hazards within the shore approach location (Suneva Lake adjustment for Route RevC2) at this time, however there remains a potential for boulders to be discovered.	A boulder field is present near Boulder Point.	Boulder zones are present southwest from Point MacKenzie and as the route approaches Miller Creek.

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

Criteria			Alternative: West Route – Applicants' Proposed Alternative – Route Revision C2	Alternative: West Route – Route Revision B	Alternative: East Route
	Currents (knots)		Shorty Creek: currents range from a mean of 2 to 3.5, and maximum from 4 to 5.9. All currents are manageable based on lay barge orientation. Boulder Point: currents range from a mean of 3.7 to 5.2 and a maximum of 5.3 to 6.4. All currents are manageable based on lay barge orientation.	Shorty Creek: currents range from a mean of 2 to 3.5, and maximum from 4 to 5.9. All currents are manageable based on lay barge orientation. Boulder Point: currents range from a mean of 3.7 to 5.2 and a maximum of 5.3 to 6.4. All currents are manageable based on lay barge orientation.	Point MacKenzie: currents range from a mean of 1.2 to 2.9, and a maximum from 2 to 4.2. Because of lay barge orientation to get around Fire Island these currents would require additional measures to maintain lay barge position during construction given the presence of additional mooring challenges. Miller Creek: currents range from a mean of 2.5 to 4.1 and a maximum of 3.3 to 5.7. All currents are manageable based on lay barge orientation.
	Ice	Presence of Ice	Approximately 2.54 miles of the route are between 0 and 33-foot water depth.	Approximately 2.1 miles of the route are between 0 and 33-foot water depth.	Approximately 2.9 miles are between 0 and 33-foot water depth.
	Crossings	Pipelines	10	13	31
		Utilities (including cables)	4	2	2
	Geohazards	Fault or Fold Crossing	Crosses the Beluga and North Cook Inlet anticlines. The Beluga and North Cook Inlet main thrust faults (related to the Beluga and North Cook Inlet anticlines, respectively) are not considered to be at risk of surface rupture and therefore pose no	Crosses the Beluga and North Cook Inlet anticlines. The Beluga and North Cook Inlet main thrust faults (related to the Beluga and North Cook Inlet anticlines, respectively) are not considered to be at risk of surface rupture and therefore pose no	No known fault or fold crossing

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

Criteria				**Alternative – West Route – Applicants' Proposed Alternative – Route Revision C2**	**Alternative – West Route – Route Revision B**	**Alternative – East Route**
				hazard to the proposed pipeline. The Project is currently performing a Probabilistic Fault Displacement Hazard Analysis of the Beluga back thrust fault to better assess the potential fault displacement and hazard to the pipeline. The expectation and current understanding is that the fault displacement is small enough so as not to cause a design challenge for the pipeline.	hazard to the proposed pipeline. The Project is currently performing a Probabilistic Fault Displacement Hazard Analysis of the Beluga back thrust fault to better assess the potential fault displacement and hazard to the pipeline. The expectation and current understanding is that the fault displacement is small enough so as not to cause a design challenge for the pipeline.	
Environmental	Land Use[a] (miles)	Developed, Low Intensity		0.77	0.90	0.83
		Developed, Medium Intensity		0.05	0.10	0.01
		Developed, Open Space		0.88	3.12	2.69
		Barren		0.15	0.03	0.04
		Cultivated Crops		0.00	0.00	8.86
		Forest		60.21	55.17	60.02
		Shrub		4.66	4.44	5.85
		Wetland Crossing[b] (miles)	Estuarine and Marine Deepwater	26.58	26.79	26.53
			Estuarine and Marine Wetland	0.20	1.29	0.70

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

Criteria				**Alternative – West Route – Applicants' Proposed Alternative – Route Revision C2**	**Alternative – West Route – Route Revision B**	**Alternative – East Route**
			Freshwater Emergent Wetland	0.29	0.63	0.98
			Freshwater Forested/Shrub Wetland	5.82	7.02	6.82
			Freshwater Pond	0.00	0.16	0.05
			Riverine	0.47	0.68	0.57
			Total wetland	**35.35**	**36.57**	**35.65**
	Land Ownership	Public Land	Parcels	135	136	186
			Owners	5	5	6
			Length (miles)	89.47	88.14	89.96
		Native Lands	Parcels	13	14	11
			Owners	3	3	3
			Length (miles)	7.52	6.98	5.07
		Private	Parcels	28	27	79
			Owners	20	16	58
			Length (miles)	5.54	5.18	19.00
	Residences within 200 feet			3	2	1
	State-Designated Area Crossing (miles)		Alexander Creek State Recreation River	1.18	1.23	0.00
			Little Susitna State Recreation River	0.00	0.00	1.64
			Captain Cook SRA	0.00	0.00	3.78
			Susitna Flats State Game Refuge (SGR)	9.91	12.45	0.90

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

<table>
<tr><th rowspan="3" colspan="4">Criteria</th><th colspan="3">Alternative</th></tr>
<tr><th colspan="2">West Route</th><th rowspan="2">East Route</th></tr>
<tr><th>Applicants' Proposed Alternative – Route Revision C2</th><th>Route Revision B</th></tr>
<tr><td rowspan="15"></td><td></td><td colspan="2">Kroto and Moose Creek Recreation River</td><td>2.61</td><td>2.18</td><td>4.85</td></tr>
<tr><td colspan="3">Designated Critical Habitat</td><td>Located in Cook Inlet Beluga
Whale CHA 2</td><td>Located in Cook Inlet Beluga
Whale CHA 2</td><td>Located in the Cook Inlet Beluga
Whale CHA 1</td></tr>
<tr><td colspan="3">Essential Fish Habitat (EFH)</td><td>All of Upper Cook Inlet has been designated as EFH for five species of Pacific salmon.</td><td>All of Upper Cook Inlet has been designated as EFH for five species of Pacific salmon.</td><td>All of Upper Cook Inlet has been designated as EFH for five species of Pacific salmon.</td></tr>
<tr><td rowspan="2">Shore Fishery Leases and Tidal Easements Crossings</td><td colspan="2">Number of Fishery Leases (miles)</td><td>1
(0.02)</td><td>0</td><td>3
(0.32)</td></tr>
<tr><td colspan="2">Number of Tidal Easements (miles)</td><td>2
(0.03)</td><td>2
(0.03)</td><td>1
(0.01)</td></tr>
<tr><td colspan="3">Waterbody Crossings (Other than Cook Inlet)</td><td>36</td><td>33</td><td>22</td></tr>
<tr><td rowspan="2">Alaska Heritage Resources Survey (AHRS)[c]</td><td colspan="2">Sites Crossed</td><td>5</td><td>25</td><td>29</td></tr>
<tr><td colspan="2">Sites within 2,000 feet</td><td>49</td><td>38</td><td>65</td></tr>
<tr><td rowspan="7">Contamination Areas [d] (number of sites within 1,000 feet of the Corridor Centerline)</td><td colspan="2">Solid Waste Facilities</td><td>0</td><td>0</td><td>0</td></tr>
<tr><td rowspan="3">Known Contamination Sites</td><td>Clean-up Complete</td><td>8</td><td>7</td><td>7</td></tr>
<tr><td>Clean-up Complete – Institutional Controls</td><td>2</td><td>1</td><td>1</td></tr>
<tr><td>Open</td><td>4</td><td>6</td><td>6</td></tr>
<tr><td rowspan="2">Leaking Underground Storage Tanks (LUST)</td><td>Clean-up Complete</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td>Clean-up Complete – Institutional Controls</td><td>1</td><td>1</td><td>1</td></tr>
</table>

TABLE 10.4.3-3

Comparison of the Cook Inlet Area Pipeline (Mainline) Alternatives

				Alternative		
				West Route		
Criteria				**Applicants' Proposed Alternative – Route Revision C2**	**Route Revision B**	**East Route**
			Open	0	0	0
Practicability of Construction	Obstructions or Construction Limitations			No significant obstructions or limitations identified	No significant obstructions or limitations identified	Constrained near Point MacKenzie because of the existing power cable easement, shipping, dredge disposal and shoal caution areas, and port activities near Anchorage; strong cross currents would force additional tugs and/or anchor handling to keep vessel on station.
	Magnetic anomalies identified within 500 feet			TBD	2	2
	Known Ordnance			TBD	No known ordnance is located in the vicinity of the route.	No known ordnance is located in the vicinity of the route.

[a] National Land Cover Database

[b] Project field survey data

[c] The AHRS is a restricted inventory of all reported prehistoric, archaeological, and historic sites within the State of Alaska and is maintained by the Office of History and Archaeology. This inventory of cultural resources includes objects, structures, buildings, sites, districts, and travel ways, with a general provision that they are more than 50 years old.

[d] ADEC Contaminated Sites Program

Note: Based on alternate segments below MP 703.4

10.4.4 Minor Route Variations

10.4.4.1 Denali National Park and Preserve (DNPP)

The Applicant evaluated two route variations through the DNPP. In consultation with the Applicant, two approximately 8-mile routing options were developed that extend from approximately MP 536.10 to MP 544.31 of the Mainline Route Revision C2 (Figure 10.4.4-1). The DNPP variations pass through the Park entrance area, generally following the Parks Highway corridor. A comparison of the DNPP route variations and Mainline Route Revision C2 is provided in Table 10.4.4-1.

The DNPP route variations offer technical engineering and constructability advantages over the Mainline route. For example, the DNPP variations avoid both an undefined active fault zone near Lynx Creek and several slope instability areas along the proposed Mainline Route Revision C2. In addition, because the DNPP would be collocated near the Parks Highway it avoids the need to construct approximately 7 miles of new remote access roads that would be required for the Mainline Route Revision C2. The visual impact of a 500-foot pipeline bridge to cross the undefined fault zone in addition to elevated fault crossings design and side slope construction associated with the Mainline would be avoided by using more conventional construction within the Park. However, a disadvantage of the DNPP route variations would be the need to reduce the Parks Highway to one lane of traffic during construction adjacent to the highway (approximately 5 miles of lane closure and traffic control). Where passing lanes have been installed (approximately 1.5-mile section), two-way traffic would still be possible.

The Mainline route does not cross the Nenana River within the DNPP alternative comparison area, while the alternatives would cross the Nenana River twice. The alternatives would cross (1) north of the DNPP entrance near Parks Highway MP 238 on a foot bridge and (2) near the south end of the alternative alignment using an open cut crossing. Crossing of the Nenana River near MP 238 would be on the existing pedestrian bridge located immediately downstream of ADOT&PF Highway Bridge #1147. The preferred method would be that the pipeline crosses the river mounted to the eastern side of the pedestrian bridge piers. The bridge is owned and maintained by ADOT&PF. Attaching a pipeline to the bridge would necessitate meeting the requirements of a utility permit from ADOT&PF

The Mainline would require approximately 1.33 miles of additional access road and would result in an additional 100 feet of fault crossing as compared to the DNPP variations. Portions of the construction ROW in the Montana Creek crossing area may require a gravel work pad to protect the frozen subgrade from rutting and degradation. For both the Mainline and DNPP variations the source of the material would be a commercial site outside of the DNPP. The closest primary borrow site would be at approximately MP 551.5. There are alternate sites at approximate MP 530 (Healy) and MP 548 (Carlo Creek) that could also be used.

For the DNPP variations, access would be via the Parks Highway and existing DNPP sewage outfall road for the fault crossing and short driveways off the Parks Highway into the alignment. Access to the Mainline fault crossing and construction ROW would be via 3.15 miles of access and shoofly road plus travel along the ROW for approximately 11 miles. The Mainline haul route would also cross a new heavy equipment bridge over the Yanert Fork.

Under provisions of the Denali National Park Improvement Act (Public Law 113-33), the Secretary of the Interior may issue a ROW permit for a high-pressure natural gas transmission pipeline in non-wilderness areas within the boundary of Denali National Park and Preserve within, along, or near the approximately 7-mile segment of the George Parks Highway that runs through the Park. The law did not provide mapping of a specified route, and it did not alter the regulatory process required to authorize a transportation corridor within Alaska National Interest Lands Conservation Act (ANILCA) lands. Therefore, a project proposing to route a natural gas pipeline through DNPP would undergo approval pursuant to Title XI of ANILCA, 11 USC 1101 et seq. The law would supersede the need to demonstrate compatibility with management plans (e.g., DNNP's Consolidated General Management Plan).

According to the applicability language of ANILCA section 1104(a), if any portion of a project should traverse a conservation system unit, which includes national parks, the entire project is subject to the ANILCA process. If the entire Project is subjected to ANILCA by virtue of a very short segment of the Mainline traversing the DNPP, the regulatory burdens and complexities associated with application of the ANILCA process to the entire Project most likely make this alternative impracticable. The practicability issues could likely be resolved if the regulatory context for this variant were to change.

TABLE 10.4.4-1

Comparison of the DNPP Alternative and Mainline Route Revision C (MP 536.10 to 544.31)

Criteria				**Alternative**		
				Route Revision C2 (Applicants' proposed alternative)	**DNPP Alternative No. 1**	**DNPP Alternative No. 2**
Engineering/Technical Considerations	Pipeline Length (miles)			8.10	8.52	8.50
	Elevation Range (feet)			~1,550–2,3001	~1,550–1,900	~1,550–1,900
	Crossings (Number)	Utilities		1	5	3
		Roads		0	4	2
		Railroad		0	2	2
		Water Bodies		5	4	4
	Fault Crossings			Active Undefined 500-foot bridge spanning Lynx Creek +700 feet of aboveground fault design	Active Defined 600 feet of conventional aboveground fault design spanning Riley Creek	Active Defined 600 feet of conventional aboveground fault design spanning Riley Creek
	Geotechnical Instability Areas			Numerous interpreted slope failures along route	0	0
	Elevation Grade Change Greater than 30 Percent Requiring Special Winch Cat Operations			1 location	0	0
	Length (miles) of Greenfield Access Roads			~2.7	~0.3	~0.3
	Collocation within 500 feet of the Centerline (miles)	Roads		0	6.25	4.03
		Pipelines		0	0	0
		Powerlines		2.46	6.22	3.99
Environmental		Land Use[a] (miles)	Residential Land	0.00	0.94	0.68
			Open Land	2.84	1.61	1.34
			Forest	5.22	5.84	6.35
			Wetlands[b]	2.96	1.59	1.86

TABLE 10.4.4-1

Comparison of the DNPP Alternative and Mainline Route Revision C (MP 536.10 to 544.31)

Criteria				**Alternative: Route Revision C2 (Applicants' proposed alternative)**	**Alternative: DNPP Alternative No. 1**	**DNPP Alternative No. 2**
		Open Water		0.04	0.13	0.13
	Federal Designated Area Crossing (miles)	DNPP		0	6.17	6.15
	Stream and River Crossings	Number		7	5	5
		Number Anadromous		0	0	0
	Cultural Sites within 750 feet[d]			6	6	6
	Raptor Nests within 1 mile[e]			4	1	1
	Development[c]	Seasonal Rental Housing/Hotels within 200 feet		3	46	46
		Dwellings within 500 feet		18	144	144
	Contamination Areas[f] (number of sites within 0.5 mile of the Corridor Centerline)	Solid Waste Facilities		0	0	0
		Known Contamination Sites	Clean-up Complete	1	1	1
			Open	0	0	0

[a] National Land Cover Database (based on FERC Class attribute)

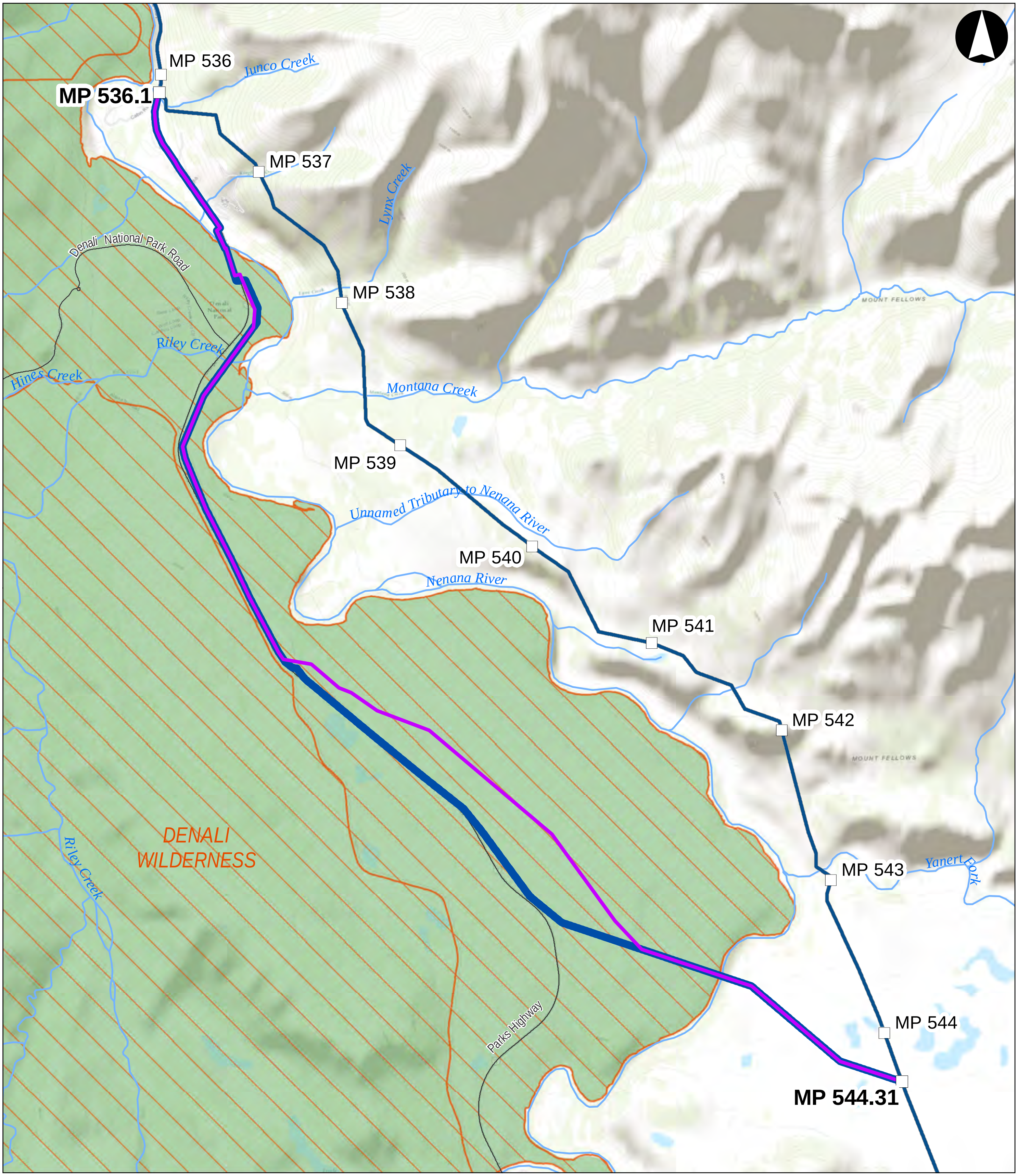
[b] National Wetland Inventory (NWI) data. Note, NWI data overlap with other land use classes.

[c] Based on High Consequence Area Dwellings

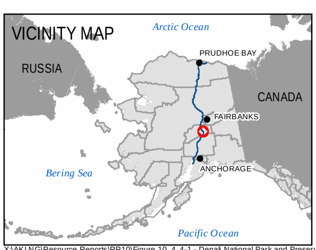
[d] The AHRS is a restricted inventory of all reported prehistoric, archaeological, and historic sites within the State of Alaska and is maintained by the Office of History and Archaeology. This inventory of cultural resources includes objects, structures, buildings, sites, districts, and travel ways, with a general provision that they are more than 50 years old.

[e] Based on field survey information

[f] ADEC Contaminated Sites Program



VICINITY MAP



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LEGEND

- Mile Post
- Alaska LNG Rev C2 Route
- DNPP Route Alternative
  - Alt 1
  - Alt 2
- Road
- Stream
- Denali Wilderness
- Denali National Park

0 0.3 0.6 1.2 Miles

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DENALI NATIONAL PARK AND PRESERVE ROUTE VARIATION

FIGURE 10.4.4-1

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10.4.4.2 Fairbanks Route Variation

The Applicant evaluated a minor route variation that would locate the Mainline closer to Fairbanks. This variation follows the Elliott Highway from Livengood through the Fairbanks area and then follows the Parks Highway before rejoining Route Revision B to Nikiski (Figure 10.4.4-2). The route variation would cover from MP 401.7 to MP 471.3 of the Route Revision C2 and would be approximately 107 miles long. South of MP 471, the route variation was assumed to follow Route Revision C2 due to the constraints in routing discussed in Section 10.4.2. A comparison of the Fairbanks route variation and Route Revision C2 is provided in Table 10.4.4-2.

The Fairbanks route variation was not further considered for inclusion in the proposed route of the Mainline due to it: 1) being 37 miles longer than the Applicants' proposed alternative; 2) crossing almost 24 more miles of wetlands; 3) crossing almost twice as many waterbodies; 4) crossing 64 more known archaeological sites; 5) impacting almost 10 miles of developed property; and 6) based on census data, crossing through approximately 10 miles of unincorporated areas of Fairbanks (north side of city). In addition, although collocated with the Elliot and Parks Highway along the alternative route, the pipeline would not necessarily be immediately adjacent to, or overlapping, with the existing rights-of-way due to construction constraints. Public access that is crossed would also be constrained or closed during active construction. The Fairbanks Route Variation was not selected after this desktop analysis indicated that the Applicants' proposed alternative would impact fewer resources as indicated above and would be more reasonable to permit than the Fairbanks variation.

TABLE 10.4.4-2

Comparison of the Fairbanks Route Variation and Mainline Route Revision B (MP 401.7 to 471.3)

Criteria				**Alternative: Route Revision C2 (Applicants' proposed alternative)**	**Alternative: Fairbanks Route Revision**
Engineering/Technical Considerations	Pipeline Length (miles)			69.44	107.13[a]
	Crossings	Pipelines		0	0
	Collocation within 500 feet of centerline (miles)	Roads		0.39	31.07
		Pipelines		0.00	24.46
		Powerlines		0.58	5.56
Environmental		Land Use[b] (miles)	Developed, Low Intensity	0.00	8.20
			Developed, Open Space	0.00	1.66
			Barren	0.18	0.43
			Cultivated Crops	0.00	0.21
			Forest	58.06	64.16
			Shrub	4.28	3.21
			Grassland/Herbaceous	1.80	0.00
			Wetland/Open Water	5.12	29.26
		State-Designated Area Crossing (miles)	Minto Flats SGR	22.10	0
			Tanana Valley State Forest	29.58	6.96
		Designated Critical Habitat Crossings		0	0
		Waterbody Crossings		36	57

TABLE 10.4.4-2

Comparison of the Fairbanks Route Variation and Mainline Route Revision B (MP 401.7 to 471.3)

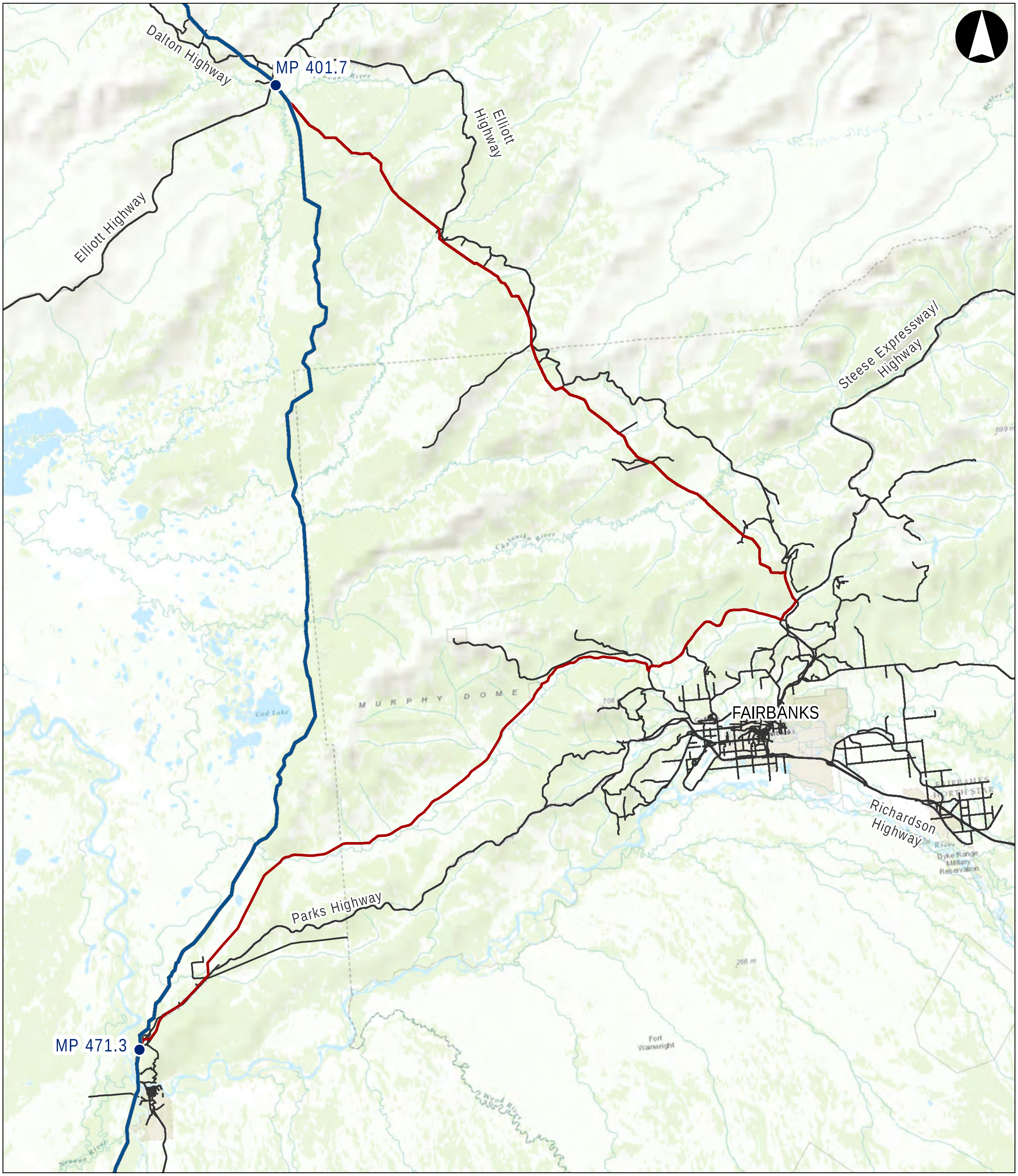
Criteria				**Alternative: Route Revision C2 (Applicants' proposed alternative)**	**Alternative: Fairbanks Route Revision**
	Census tract/PHMSA-designated unincorporated areas of Fairbanks			0	10
	Alaska Heritage Resources Survey (AHRS)[c]	Sites Crossed		6	70
		Sites within 2,000 feet		16	112
	Contamination Areas[d] (number of sites within 1,000 feet of the Corridor Centerline)	Solid Waste Facilities		0	0
		Known Contamination Sites	Clean-up Complete	0	1
			Clean-up Complete – Institutional Controls	0	0
			Open	0	1
		LUST	Clean-up Complete	0	2
			Clean-up Complete – Institutional Controls	0	2
			Open	0	0

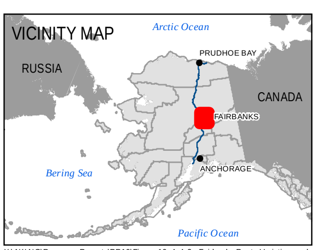
[a] The additional pipeline length increases costs by approximately $300,000,000.

[b] National Land Cover Database

[c] The AHRS is a restricted inventory of all reported prehistoric, archaeological, and historic sites within the State of Alaska and is maintained by the Office of History and Archaeology. This inventory of cultural resources includes objects, structures, buildings, sites, districts, and travel ways, with a general provision that they are more than 50 years old.

[d] ADEC Contaminated Sites Program





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LEGEND

- Milepost (Where routes diverge)
- Pipeline Rev C2 Route
- Fairbanks Route Variation
- Road

0 3.25 6.5 13 Miles

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FAIRBANKS ROUTE VARIATION

FIGURE 10.4.4-2

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10.4.4.3 Route Revision C2 (Proposed Alternative)

As noted in Section 10.4.3.1.3, a common alignment with the ASAP Project was developed for a majority of the northern 680 miles of the route. In total, there were 34 potential route changes, or route variations, created as a result of the work done comparing the ASAP version 5 route and the Project's Route Revision A corridor to develop Route Revision B, filed in the June 14, 2016 draft application for the Project. South of the common corridor, six additional potential route refinements were identified along the Project's Route Revision A corridor, including the west and east alternatives that cross Cook Inlet (discussed previously in Section 10.4.3.2). The identified reroutes were proposed to avoid cultural resource sites, a high bluff on the Cook Inlet shoreline, lakes, the Kenai NWR, and two sections of pipeline designated in a Class 3 Location.[21]

The Applicant subsequently reviewed 40 proposed changes to the Route Revision A corridor. As the Revision B route was developed, the Project's socioeconomic team provided input on routing near Healy, developed areas near DNPP, McKinley Park Village and the Intertie, near the Alaska Veterans Memorial and Byers Lake Campground, near Troublesome Creek and the proposed Chulitna River crossing, near the Mt. McKinley Princess Wilderness Lodge, through the Trapper Creek community, and near Beluga. The pipeline route took into consideration, to the extent practicable, socioeconomic concerns, including proximity to residences and businesses, utilizing existing utility corridors, maximizing buffers near public recreations sites, minimizing adverse effects to sensitive viewsheds, reducing potential noise and light emissions near commercial lodging, and minimizing impacts to important trails and access points.

Following the workshop, one of the proposed reroutes was dismissed and the remainder used to create Route Revision B. This reroute resulted in a reduction in environmental impacts as summarized in Table 10.4.4-3.

The Applicant has subsequently reviewed additional comments received from state agencies and the public on the Route Revision B. The review of these comments resulted in additional minor route variations to accommodate or address some of the comments raised. The result is the proposed Route Revision C2. In summary, the Applicant reviewed 114 proposed changes to the Route Revision B corridor, of which 96 were accepted to develop Route Revision C2. These minor reroutes resulted in an additional reduction in environmental impacts as summarized in Table 10.4.4-3. A description of these refinements is provided in Table 10.4.4-4 and mapping of the alternatives is provided in Appendix C.

USFWS had previously commented on Route Revision A of the Mainline, suggesting that the segment from the Tatalina River (MP 430) to Chatanika River (MP 439) be reviewed to determine if there was a potential reroute which could place the Mainline higher up along the mountain slope to avoid wetlands within the flats area. The Applicant reviewed a potential shift of this segment of the route to the east in this area, however, based on engineering and construction constraints, a practical reroute was not identified. A minor reroute was made for Route Revision C that provides the best alignment for crossing both the Tatalina River and Washington Creek (see Table 10.4.4-4). East of the Tatalina river crossing there are several tight

[21] Class locations are determined by PHMSA regulations (49 C.F.R. 192) based on population density within set distances of the pipeline: Class 1 – Offshore or 10 or fewer buildings intended for human occupancy; Class 2 – More than 10 but fewer than 46 buildings intended for human occupancy (ends 220 yards from the nearest building); Class 3 – 46 or more buildings intended for human occupancy (ends 220 yards from the nearest building); or where the pipeline lies within 100 yards of either a building or a small, well-defined outside area (such as a playground, recreation area, outdoor theater, or other place of public assembly) that is occupied by 20 or more persons on at least 5 days a week for 10 weeks in any 12-month period; Class 4 – Buildings with four or more stories above ground are prevalent (class 4 location ends 220 yards from the nearest building with four or more stories above ground).

meanders, as well as abandoned channels to the east and south, which would make crossing challenging. Proposed Route Revision C through the Tatalina River to Chatanika River area:

- Remains along the summer ridge as far south as practicable before dropping into the Tatalina River flats;
- Minimizes crossing of saturated wetlands to reach the timber covered side slopes south of Washington Creek;
- Takes into account the steep side slopes consisting of silty soils (Fairbanks silts) from MP 433 to MP 439;
- Recognizes that the ridgeline to the east is narrow and runs into a steep bluff where it intersects the Chatanika River. Following the ridge line would add several miles of pipeline with limited to no access; and
- The Chatanika River crossing alignment is constrained by the presence of private land parcels and native allotments to the east and west.

This section of the Mainline would be built in the winter with almost half of the section (approximately 4 miles) using a frost packed construction mode, reducing potential impacts to wetlands. Rerouting to the east would result in a longer route, the requirement of building construction access, and crossing soil conditions that could result in the need to construct during the summer for safety reasons.

TABLE 10.4.4-3

Summary of Minor Route Revisions (Refinements)

Refinement		**Difference Between Route Revisions**
Minor Route Revisions from Route Revision A to Route Revision B		
Total Pipeline Length		Reduction of approximately 2.3 miles
Wetland Crossings	Total	Reduction of approximately 1 mile of wetlands crossing
	Forested	Reduction of approximately 7 miles of forested wetlands crossing
Stream Crossings	Total	Additional 13 stream crossings
	Major (width at crossing > 100 feet)	Reduction of seven major stream crossings
	Anadromous	Reduction of one anadromous stream crossing
Contaminated Sites		Reduction of three sites within 500 feet
Cultural Resources		Increase in three known sites of cultural resources within 500 feet
Minor Route Revisions from Route Revision B to Proposed Route Revision C2		
Total Pipeline Length		Addition of approximately 2.3 miles
Wetland Crossings	Total	Reduction of approximately 0.5 acre
	Forested	Reduction of approximately 0.6 acre
Stream Crossings	Total	Reduction in five stream crossings
	Major (width at crossing > 100 feet)	Addition of one major waterbody crossing
	Anadromous	Addition of one anadromous stream crossing
Contaminated Sites		Reduction of three sites within 500 feet
Cultural Resources		Reduction of seven known cultural resources within 500 feet

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 1 (B-000-0.00-0.54)	0.00	0.40	0.40	0.00	Minor route adjustment to align with the GTP footprint
RevB to Rev C2 No. 2 (B-000a-0.40-3.31)	0.40	3.31	2.73	-0.18	Avoids crossing part of the GTP footprint that will be part of the associated facilities
RevB to Rev C2 No. 3 B-001-3.48-4.90	3.48	4.90	1.41	-0.01	Avoids unnecessary bends by creating a straight crossing alignment of multiple above-ground pipelines, a pipeline service road, and Spine Road
RevB to Rev C2 No. 4 B-002-21.46-24.87	21.46	24.87	3.43	+0.02	Avoids a pingo area and remnants of a pond
RevB to Rev C2 No. 5 B-002a-65.00-71.40	65.00	71.40	6.58	+0.18	Minor route adjustment to reduce impacts to wetlands, follow the fall lines, and straighten the Dalton Highway crossing
RevB to Rev C2 No. 6 B-003-82.94-85.73	82.94	85.73	2.75	-0.04	Avoids a cultural resource area and reduces side slopes
RevB to Rev C2 No. 7 B-003a-86.98-89.08	86.98	89.08	1.95	-0.15	Minor route adjustment to shorten the route and follow fall lines

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 8 B-004-96.73-97.13	96.73	97.13	0.39	-0.01	Minor route adjustment to shift away from a potential geohazard area (flow slide)
RevB to Rev C2 No. 9 B-005-100.-101.81	100.31	101.81	1.44	-0.06	Minor route adjustment to straighten the route
RevB to Rev C2 No. 10 B-006-115.47-116.44	115.47	116.44	0.91	-0.06	Minor route adjustment to improve the waterbody crossing alignment
RevB to Rev C2 No. 11 B-008-135.09-135.73	135.09	135.73	0.68	+0.04	Minor route adjustment that shifts a bend in the route to the top of the slope in a permafrost area
RevB to Rev C2 No. 12 B-009-138.09-140.07	138.09	140.07	2.02	+0.04	Avoids a cultural resource area and follows the fall lines
RevB to Rev C2 No. 13 B-010-144.05-145.01	144.05	145.01	0.98	+0.02	Avoids a pinch point between a small lake and the Dalton Highway
RevB to Rev C2 No. 14 B-011-145.57-147.23	145.57	147.23	1.69	+0.03	Avoids a cultural resource area and follows the terrain

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 15 B-011a-148.37-149.55	148.37	149.55	1.20	+0.02	Minor route adjustment to match the revised aboveground facility location (Galbraith Lake Compressor Station)
RevB to Rev C2 No. 16 B-012-150.75-151.46	150.75	151.46	0.71	+0.00	Avoids footprint encroaching on Dalton Highway bridge river training embankments at Roche Mountonnee Creek crossing
RevB to Rev C2 No. 17 B-014-165.83-167.22	165.83	167.22	1.40	+0.01	Minor route adjustment to straighten the Atigun River channel crossing and increase the setback from the rock glacier. The reroute then generally parallels the abandoned TAPS pipe to avoid going over the Atigun River alluvial fan
RevB to Rev C2 No. 18 B-015-167.22-167.73	167.22	167.73	0.52	+0.01	Minor route adjustment to generally parallel the abandoned TAPS route and stay in the Upper Atigun River at the toe of the alluvial fan
RevB to Rev C2 No. 19 B-016-177.45-178.03	177.45	178.03	0.58	0.00	Minor route adjustment to shift the bend out of the Dieterich River flood plain and away from a potential geohazard area (shallow slide), follows the fall line
RevB to Rev C2 No. 20 B-017-178.03-179.30	178.03	179.30	1.21	-0.06	Minor route adjustment to shift into the Upper Dietrich River, to straighten and shorten the alignment, and take a midpoint between the Dalton Highway and steep mountain slopes
RevB to Rev C2 No. 21 B-018-179.30-183.95	179.30	183.95	4.44	-0.21	Minor route adjustment to avoid the eroding bank of the Dietrich River, improves crossing alignment of TAPS and Dalton Highway

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 22 B-019-193.70-193.92	193.70	193.92	0.21	-0.01	Minor route adjustment to avoid an active rock quarry
RevB to Rev C2 No. 23 B-021-213.71-214.64	213.71	214.64	0.92	-0.01	Removes the bend on south side of West Fork Sukakpak Creek crossing
RevB to Rev C2 No. 24 B-023-218.51-219.75	218.51	219.75	1.22	-0.02	Minor route adjustment to avoid a pond and active material site, creates additional setback from the highway to allow for construction
RevB to Rev C2 No. 25 B-024-219.75-221.52	219.75	221.52	1.78	+0.01	Avoids a cultural resource area
RevB to Rev C2 No. 26 B-025-226.87-228.19	226.87	228.19	1.34	+0.02	Minor route adjustment to reduce side slope and increase the setback from unstable slopes
RevB to Rev C2 No. 27 B-026-244.29-246.83	244.29	246.83	2.53	-0.01	Minor route adjustment to increase setback from a lake and straightens the approach to the Rosie Creek crossing
RevB to Rev C2 No. 28 B-027-249.49-251.83	249.49	251.83	2.29	-0.05	Avoids a cultural resource area, reduces side slopes, and increases the setback from a lake

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 29 B-029-266.89-268.34	266.89	268.34	1.48	+0.03	Avoids a cultural resource area
RevB to Rev C2 No. 30 B-030-280.48-282.14	280.48	282.14	1.58	-0.08	Avoids a cultural resource area and potential geohazard (avulsion)
RevB to Rev C2 No. 31 B-031-285.94-287.96	285.94	287.96	2.10	+0.08	Minor route adjustment to follow fall lines
RevB to Rev C2 No. 32 B-032-297.65-303.53	297.65	303.53	5.76	-0.12	Minor route adjustment to follow the fall lines and avoids a potential geohazard (slides)
RevB to Rev C2 No. 33 B-033-356.27-358.43	356.27	358.43	2.18	+0.02	Minor route adjustment to straighten the Yukon River crossing alignment as far north and south as possible to minimize the need for false ROW and bends
RevB to Rev C2 No. 34 B-034-365.66-367.26	365.66	367.26	1.62	+0.02	Minor route adjustment to reduce wetland impacts and reduce side slope
RevB to Rev C2 No. 35 B-035-369.20-370.98	369.20	370.98	1.82	+0.04	Minor route adjustment to reduce wetland impacts and avoid potential geohazard (slides)

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 36 B-036-375.65-377.00	375.65	377.00	1.31	-0.04	Avoids a cultural resource area and straightens the route
RevB to Rev C2 No. 37 B-037-381.71-382.79	381.71	382.79	1.09	+0.01	Minor route adjustment to straighten the Hess Creek crossing and floodplain, bend is moved well south of active channels
RevB to Rev C2 No. 38 B-038a-385.24-389.48	385.24	389.48	4.20	-0.04	Minor route adjustment to avoid a potential geohazard (frozen upland silty soils on a steep and unstable slope)
RevB to Rev C2 No. 39 B-041-396.18-396.85	396.18	396.85	0.68	+0.01	Minor route adjustment to improve the crossing alignment of a wetland area
RevB to Rev C2 No. 40 B-042-398.89-400.09	398.89	400.09	1.20	0.00	Minor route adjustment to straighten out a bend and cross below the confluence of multiple drainage courses
RevB to Rev C2 No. 41 B-042a-410.34-425.13	410.34	425.13	13.34	-1.45	Minor route adjustment to follow fall lines and better terrain
RevB to Rev C2 No. 42 B-043-425.51-432.18	425.51	432.18	6.70	+0.03	Avoids a cultural resource area, straightens the Tatalina River crossing, and reduces wetland impacts

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 43 B-043a-432.34-432.75	432.34	432.75	0.41	0.00	Minor route adjustment to improve a creek crossing (straight stretch)
RevB to Rev C2 No. 44 B-044-440.57-445.46	440.57	445.46	4.62	-0.27	Minor route adjustment to reduce wetland impacts
RevB to Rev C2 No. 45 B-046-450.06-450.46	450.06	450.46	0.34	-0.06	Minor route adjustment to rescue bend angle and better follow terrain
RevB to Rev C2 No. 46 B-047-463.63-465.80	463.63	465.80	2.11	-0.06	Minor route adjustment to avoid ponds and reduce wetland impacts
RevB to Rev C2 No. 47 B-048-467.75-469.65	467.75	469.65	1.78	-0.12	Minor route adjustment to reduce wetland impacts
RevB to Rev C2 No. 48 B-049-499.39-501.93	499.39	501.93	2.52	-0.02	Minor route adjustment to the upper river terrace to reduce the potential for possible flooding
RevB to Rev C2 No. 49 B-050-502.74-504.87	502.74	504.87	2.09	-0.04	Minor route adjustment to increase setback from Nenana River and potential for possible flooding

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 50 B-051-507.56-509.20	507.56	509.20	1.67	+0.03	Minor route adjustment to reduce wetland impacts and avoid private lands
RevB to Rev C2 No. 51 B-052-516.47-516.81	516.47	516.81	0.34	0.00	Minor route adjustment to improve a creek crossing and better align for a powerline crossing
RevB to Rev C2 No. 52 B-053-517.92-518.42	517.92	518.42	0.52	+0.02	Minor route adjustment to match aboveground facility location (Healy compressor station)
RevB to Rev C2 No. 53 B-055-528.10-529.85	528.10	529.85	1.83	+0.08	Minor route adjustment to avoid a potential geohazard (solifluction and earthflow))
RevB to Rev C2 No. 54 B-056-532.04-532.87	532.04	532.87	0.81	-0.02	Minor route adjustment for improved crossing of a railroad and Nenana River gorge at Moody
RevB to Rev C2 No. 55 B-057-532.87-533.68	532.87	533.68	Superseded by Nenana Canyon Reroute	N/A	Minor route adjustment to straighten the pipeline alignment through Coyote, Dragonfly and Eagle Creek incised ravine crossings
RevB to Rev C2 No. 56 B-059-534.30-535.23	534.30	535.23	Superseded by Nenana Canyon Reroute	N/A	Minor route adjustment to improve the crossings at Fox Creek and Grizzly Creek

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 57 Nenana Canyon Reroute	532.87	536.68	3.72	-0.09	Nenana Canyon Reroute - Reroute duplicates the Applicants proposed in-state pipeline route which trades the difficult terrain (steep side slopes, incised creek crossings and no existing access) with following the ditch line along the east side of the highway
RevB to Rev C2 No. 58 B-061-536.68-536.87	536.68	536.87	0.20	+0.01	Minor route adjustment to improve the crossing alignment of Junco Creek
RevB to Rev C2 No. 59 B-063-536.87-539.33	536.87	539.33	2.50	+0.04	Minor route adjustment to follow fall lines and slightly shallower side slopes, straightens creek crossings and removes a bend in the aboveground fault crossing at Lynx Creek
RevB to Rev C2 No. 60 B-064-539.78-540.32	539.78	540.32	0.53	-0.01	Minor route adjustment to straighten the route
RevB to Rev C2 No. 61 B-065-542.48-543.66	542.48	543.66	1.19	+0.01	Minor route adjustment to straighten the route and improve the river crossing
RevB to Rev C2 No. 62 B-066-553.10-553.59	553.11	553.59	0.57	+0.07	Minor route adjustment to avoid a pond and side slopes
RevB to Rev C2 No. 63 B-067-559.89-561.82	559.89	561.82	2.55	+0.62	Minor route to straighten out the Denali fault line crossing and shift the Nenana River crossing to a straight reach along the Nenana River

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 64 B-067a-563.17-564.24	563.17	564.24	1.13	+0.06	Minor route adjustment to reduce wetland impacts and side slopes
RevB to Rev C2 No. 65 B-068-571.72-574.62	571.72	574.62	2.84	-0.06	Minor route adjustment to reduce wetland impacts and improve the crossing alignment for the George Parks Highway and Alaska Railroad
nenana native allotment reroute	471.05	471.66	0.61	0.00	to avoid native allotment
RevB to Rev C2 No. 66 B-069-581.00-582.12	581.00	582.12	1.11	-0.01	Minor route adjustment to avoid University of Alaska property and reduces wetland impacts
RevB to Rev C2 No. 67 B-071a-589.06-590.06	589.06	590.09	0.97	-0.06	Minor route adjustment to reduce wetland impacts with a better crossing alignment of the East Fork of the Chulitna River
RevB to Rev C2 No. 68 B-072-590.09-593.16	590.09	593.16	3.27	+0.20	Minor route adjustment to reduce wetland impacts and side slopes
RevB to Rev C2 No. 69 B-072a-593.16-595.56	593.16	595.56	2.50	+0.10	Minor route adjustment to reduce wetland impacts and rough terrain

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 70 B-073-597.03-601.27	597.03	601.27	4.18	-0.06	Avoids a potential geohazard (debris lobes) and follows terrain
RevB to Rev C2 No. 71 B-074-607.07-610.41	607.07	610.41	3.31	-0.03	Minor route adjustment to reduce impacts to wetland and private lands
RevB to Rev C2 No. 72 B-075-612.29-613.20	612.29	613.20	0.92	+0.01	Minor route adjustment to reduce side slopes and follow terrain
RevB to Rev C2 No. 73 B-076-622.55-623.85	622.55	623.85	1.31	+0.01	Minor route adjustment to avoid steep slopes
RevB to Rev C2 No. 74 B-077-629.81-631.32	629.81	631.32	1.42	-0.09	Minor route adjustment to shift away from the Byers Lake campground
RevB to Rev C2 No. 75 B-080-648.07-657.36	648.07	657.36	9.39	+0.10	Minor route adjustment to shift away from recreational cabins on the west side of the George Parks Highway
RevB to Rev C2 No. 76 B-081-660.52-661.53	660.52	661.53	0.88	-0.13	Minor route adjustment to shorten the route without impacting additional wetlands

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 77 B-082-674.36-676.38	674.36	676.38	2.05	+0.03	Minor route adjustment to match aboveground facility location (Rabideaux Creek compressor station)
RevB to Rev C2 No. 78 B-083-676.38-677.15	676.38	677.15	0.80	+0.03	Minor route adjustment to reduce side slopes
RevB to Rev C2 No. 79 B-084-681.22-682.38	681.22	682.38	1.18	+0.02	Minor route adjustment to reduce bends and follow terrain
RevB to Rev C2 No. 80 B-085-690.05-691.59	690.05	691.59	1.64	+0.10	Minor route adjustment to avoid bog areas
RevB to Rev C2 No. 81 B-087-703.47-706.53	703.47	706.53	3.26	+0.20	Avoids the center of a cultural resource area and allows for a trenchells construction method across the Deshka River
RevB to Rev C2 No. 82 B-088a-723.94-725.60	723.94	725.60	1.68	+0.02	Avoids a potential geohazard (liquefaction)
RevB to Rev C2 No. 83 B-089-726.89-727.88	726.89	727.88	0.94	-0.05	Minor route adjustment to increase the setback distance from a cabin

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 84 B-090-731.73-734.30	731.73	734.30	2.56	-0.01	Minor route adjustment to avoid a pond and side slopes
RevB to Rev C2 No. 85 B-091-735.00-739.44	735.00	739.44	4.44	+0.00	Avoids a potential geohazard (slide)
RevB to Rev C2 No. 86 B-092-739.44-754.16	739.44	754.16	9.08	-5.64	Avoids a cultural resource area and reduces wetland impacts
RevB to Rev C2 No. 87 B-093-754.16-757.66	754.16	757.66	3.54	+0.04	Minor route adjustment to provide a better alignment for the Beluga River crossing
RevB to Rev C2 No. 88 B-093a-759.56-760.05	759.56	760.05	0.53	+0.04	Minor route adjustment to provide a better alignment for a road crossing
RevB to Rev C2 No. 89 B-094-760.92-762.93	760.92	762.93	2.06	+0.05	Minor route adjustment to reduce wetland impacts, increase the set-back from a lake, and provide a better alignment for the Threemile Creek crossing

TABLE 10.4.4-4

Minor Route Revisions (Refinements) Made to Route Revision B to Create Proposed Route Revision C2

Route Refinement (Name)	Mainline MP[a]		Variation Length (miles)	Difference in Length from Route Revision (miles)	Refinement Rationale[a]
	Starting	Ending			
RevB to Rev C2 No. 90 Cook Inlet - Offshore Reroute	763.82	794.49	31.65	+0.98	Cook Inlet Offshore Reroute – See Section No. 10.4.3.2 and Table 10.4.3-2. Minor route adjustment to the offshore route to improve shoreline crossings (as well as for other subsea issues) to locations with narrower mudflats. Onshore pipeline routing adjusted to match these new shoreline crossing locations. On the north side of Cook Inlet, the route generally follows the Beluga Highway going southwest about 5,100 feet to a point just south of the existing barge landing. On the south side of Cook Inlet, the shoreline crossing was moved approximately 2 miles east of the Boulder Point crossing. The onshore reroute heads southwest for about 3.6 miles, avoiding private lots and lakes while minimizing wetlands, sensitive cultural resource areas and grading requirements
RevB to Rev C2 No. 92 B-095-794.49-795.73	794.49	795.73	1.25	+0.01	Minor route adjustment to follow fall lines, avoid a private lot, and increase the setback from the shoreline bluff
RevB to Rev C2 No. 93 B-096-797.14-798.39	797.14	798.39	1.29	+0.04	Minor route adjustment to avoid a pond, follow fall lines, and increase the setback from a residence. Parallels and abuts existing linear infrastructure
RevB to Rev C2 No. 94 B-097-801.62-802.17	801.62	802.17	0.55	+0.00	Minor route adjustment to increase the setback from existing commercial buildings
RevB to Rev C2 No. 95 B-098-802.17-804.33	802.17	804.33	4.4	+2.24	Minor route adjustment to increase the setback from an existing commercial property and align with Liquefaction Facility

[a] MP of the Route Revision being refined

[b] Field surveys were incomplete at the time of this analysis. In addition, only Phase 1 cultural resource studies have been conducted; no eligibility determinations have been made.

10.4.5 Design Alternatives

10.4.5.1 Aboveground versus Belowground Pipeline Design

On the Alaska North Slope, the majority of existing in-field pipelines are above ground due to the permafrost soil conditions. These aboveground systems include multi-phase production lines, water injection lines, and other liquid lines, all of which generally transport warm or hot fluids. If they were buried, warm, or hot pipelines located in thaw-unstable, perennially frozen soils, would transfer heat to the ground, causing thermal degradation of the permafrost leading to subsidence, potential pipe integrity problems, and disruption of surface hydrology. Because of this, buried warm lines might need to be insulated for flow assurance and stability issues.

While crossing most of the permafrost area, the pipeline would transport a gaseous product at a mean annual temperature below freezing. Permafrost degradation around the pipe is therefore not a consideration. Because the pipeline is buried, neither the pipeline steel nor the flowing gas are subjected to wide temperature swings including extreme cold during winter, and a buried pipeline reduces the risk associated with third-party damages or acts of sabotage.

Although both modes (aboveground or belowground) of pipeline design are safe methods of gas transportation, there are tradeoffs in the use of the two different modes. For example, considerations for a belowground pipeline design on the North Slope include the increased cost of inspection and maintenance, as well as restoration and maintenance of the ROW. Alternatively, considerations for the aboveground mode include gas flow assurance, cost of VSM materials and installation, the use of advanced line pipe metallurgy to achieve line pipe properties at extremely low ambient temperatures, associated costs of this advanced line pipe metallurgy and testing, and visual impacts.

10.4.5.1.1 Mainline

The Project evaluated the use of an aboveground versus belowground pipeline design, and selected a belowground design as the proposed alternative. Major factors that were considered and assessed to determine the practicality of an aboveground design alternative versus belowground design include:

- Does the alternative fulfill the Project purpose – considered operational reliability and feasibility;
- Can the alternative be achieved with existing technology – considered current line pipe technology;
- Is the alternative safe – considered safety and security;
- What are the environmental impacts of the alternative – considered footprint and permanent impacts; and
- What are the cost differences?

10.4.5.1.1.1 Operational Reliability

For the belowground design, the backfill substantially would reduce the seasonal ambient temperature fluctuations the pipeline would be exposed to, and the minimum temperature would not drop below the threshold that facilitates liquid hydrocarbon drop-out. Therefore, natural gas transported would remain in a gaseous state throughout the normal expected range of pressures and temperatures. This allows the system to handle a potential shutdown or other upset conditions and be restarted at different pressures and flow rates year-round. The lower maximum ambient temperature would also increase the summer efficiency of the gas pipeline resulting in a more uniform seasonal pipeline capacity.

For the aboveground design, the pipeline would be exposed to the entire range of seasonal ambient temperatures from -70 °F to +80 °F over the pipeline route. During a shutdown or other upset condition in the winter, the gas would chill, resulting in liquid drop-out in the pipeline. This liquid would settle in low points until the gas rate/velocity was increased high enough to sweep the liquid downstream. Controlling the gas velocity so it would steadily sweep the liquid out of the line without creating a liquid slug that is larger than the downstream facility could handle would be very difficult. Depending on the amount of liquids that dropped out, the restart procedure could take days or weeks to implement depending on the capacity of the liquid handling equipment of the downstream facilities. The optimum rate required to safely sweep out the liquids may not match the allowable LNG train rates, potentially extending the ramp up time or requiring flaring of the volume between the optimum rate and the LNG facilities allowable rates.

Other factors assessed included construction and operations, environmental and social impacts, and cost. For the purposes of this evaluation, the routing of the aboveground and belowground pipelines were considered the same.

A comparison of the two alternative designs is provided in Table 10.4.5-1.

TABLE 10.4.5-1

Comparison of Aboveground Versus Belowground Mainline Design

Criteria		**Belowground (Applicants' proposed alternative)**	**Aboveground**
Engineering/Technical Considerations	Safety and Security	Accidental damage is less likely to occur and less likely to be damaged (intentionally or unintentionally)	More susceptible to vandalism or accidental damage; for example, easier target for damage due to gun fire/hunting TAPS has incurred multiple impacts from rifle bullets in its operating history.
	Operability	Minimal potential for liquid drop-out since the gas temperature is maintained above the temperature where liquid would condense out of the natural gas as a result of the moderate temperature of the soil around the pipe In discontinuous permafrost the potential for thaw settlement and frost heave is mitigated by controlled cooling of the discharge gas from the compressor stations.	Operations procedures become more complex to manage hydrocarbon liquid drop-out that would negatively impact operating flexibility, resulting in lower LNG production. Aboveground design subjects the pipeline to lower temperatures that will cause heavier hydrocarbons to condense from the gaseous phase into liquid within the pipeline during integrity pig runs, shutdown, or upset conditions. Additional facilities (and footprint) at compressor stations would be required to handle the large quantity of

TABLE 10.4.5-1

Comparison of Aboveground Versus Belowground Mainline Design

Criteria		**Belowground (Applicants' proposed alternative)**	**Aboveground**
			highly volatile liquids. Liquids would then need to be transported, either back to the GTP or sold as a fuel for use elsewhere.
	Line Pipe Technology	Belowground line pipe is proven technology; it does not require -50 °F ultra-low temperature steel toughness requirements. More mills can manufacture this size and kind of pipe. The procedures and quality assurance requirements are proven for pipe manufacturing, belowground construction, installation, and operations.	Aboveground line pipe requires advanced steel manufacturing technology to achieve line pipe specifications with ultra-low temperature steel toughness (pipe meeting -50 °F toughness requirements require tighter chemistry and manufacturing tolerances) Higher risk of extended pipe procurement period, (less procurement options globally) and pipeline schedule risk in trying to find, test, and perform quality assurance on the materials used for this quality of pipe
	Logistics	No incremental logistics	Requires increase in logistical effort and cost for VSM materials, pipe insulation, and field joint insulation, resulting in an increase in shipping, barge, truck, and rail transport
Environmental and Social		Visual resource impacts would include only the linear cleared corridor. Vegetation would be allowed to re-establish on the construction ROW. Smaller footprint for aboveground facilities Construction ROW wider due to need for the excavation safety requirements and to store trench material during construction More initial wetland impacts due to trenching, but restoration efforts will facilitate wetlands restoration where permanent fill is not required The route has soil types that have a high susceptibility to erosion, which could occur as a result of both the ROW regrading and ditching. The *Project Restoration Plan* will provide mitigation strategies to reduce the potential for erosion and sedimentation. The potential for aufeis formation in stream crossings would be mitigated by both the operating procedures and Project design documents. The Project would have design, construction and operating procedures/ practices that would implement permafrost Best Management Practices (BMPs) to reduce any impact the	Post-construction visual impacts would include linear cleared corridor and pipeline structure at ground observer height of 7 to 12 feet. Increase in the footprint of aboveground station facilities Construction ROW generally narrower with no ditch excavation and no need to store trench material. Fewer initial impacts to wetlands for VSMs, however, more granular road for operational maintenance may be required. Soil erosion and drainage: The route has soil types that have a high susceptibility to erosion; erosion can occur as a result of ROW grading to prepare the ROW for safe construction. The *Project Restoration Plan* will provide mitigation strategies to reduce the potential for erosion and sedimentation. The clearance below the pipeline would be increased above the flood level/ice float levels potentially resulting in greater visual impact. The Project would have design construction and operating procedures/practices that would implement permafrost BMPs to reduce any impact the VSM and pipeline installation would have on the permafrost. The pipeline could be a potential barrier to wildlife passage and to authorized

TABLE 10.4.5-1

Comparison of Aboveground Versus Belowground Mainline Design

Criteria	Belowground (Applicants' proposed alternative)	Aboveground
	pipeline ditching, backfill, and construction would have on the permafrost. Allows for continued free passage of wildlife No barriers to all-terrain vehicles or snowmachine traffic, where authorized on the ROW.	snowmachine or all-terrain vehicle traffic, but the mitigation measure of elevating the bottom of the pipe to an appropriate height would greatly reduce the potential for the pipe to act as a barrier.
Practicability of Construction	To mitigate unstable backfill material thaw-stable backfill materials would be used in accordance with Project construction documentation. Ditch plugs and other mitigation methods would also be used to ensure trench stabilization by implementing pipeline construction BMPs. Welding procedures: The belowground pipeline would use proven welding procedures.	The use of VSMs would result in an increase in materials and work hours for construction, resulting in increased schedule risk and longer worker safety exposure while working outside to install VSMs and install the aboveground pipeline in cold weather. Welding procedures: The aboveground pipeline would require the development of a state-of-the-art weld qualification program as a result of the low temperature weld properties required for the aboveground pipeline. This would cause scheduling risk since it would require extensive testing and PHMSA approval.
Cost	Reduced installation cost due to no VSMs, no pipe insulation, conventional pipe material, minimal liquid handling infrastructure Increased operating costs required for reclamation activities spread over 15+ years Lower operating costs due to the system design that would mitigate melting of permafrost and issues relating to non-continuous permafrost. Generally, operating costs have a lower impact on the cost of gas supply to market versus significant up-front increases in construction costs. Delivery of all the British Thermal Unit content of the gas to the LNG facility, allowing the sale of the product where there is a larger market	At least a 25-percent higher capital construction cost due to VSMs (purchase, manufacture, and installation), pipe insulation, special low temperature pipe, and tighter welding acceptance criteria. This increase does not include the additional capital and operating costs required at the facilities to handle condensed liquid or additional capital if construction schedule requires an extension. A reduced level of reclamation activities would still be required on the ROW over the next 15 years. Complex operational restrictions and procedures increase risk for loss of LNG production. Increased operational costs for pipeline and VSMs monitoring and mitigation. Requirement to dispose of the condensed hydrocarbon liquid at field locations that have no local markets, requiring the need for pressurized trucks (or stabilization infrastructure) to transport the condensate to market. These, in turn, would require additional footprint for tankage at the compressor stations and at the end use location.

A more-detailed analysis of the information provided in Table 10.4.5-1 is provided as follows.

10.4.5.1.1.2 Safety and Security

- Belowground pipelines are a proven, reliable design that prioritizes pipeline integrity and safety first. This is reflected in the safety record of the pipeline industry; it is the safest mode of transportation of hydrocarbons in the United States.

- The aboveground design is more vulnerable to accidental damage and intentional vandalism. An aboveground design could leak and potentially ignite if hit by gunfire (accidental or intentional). The pipe and associated VSMs are more vulnerable to strikes from aircraft and ground-based vehicles than a buried pipeline.

- The belowground pipe is restrained and insulated by the soil within which it is buried. In the event of a pipeline failure and resultant fire, sections of the pipe that are upstream and downstream of the rupture are largely shielded from damaging effects of thermal radiation (flame) and vibration by the surrounding/restraining soil.

- The aboveground pipe is relatively unrestrained. In the event of a failure, the resultant forces caused by the gas escaping could result in movement of sections of the pipeline and lead to longer sections of the pipeline being subjected to high thermal loads resulting in damaged pipe and/or damaged insulation. The pipe movement and lack of restraint may also result in pipe fatigue and failure issues resulting in requiring the replacement of additional sections of pipe and/or additional sections of pipe due to insulation damage. The movement could also cause detachment of additional pieces of pipe that could be ejected, potentially resulting in damage to nearby infrastructure.

10.4.5.1.1.3 Operational Reliability and Feasibility

- Hydrocarbon liquid is anticipated to condense in the pipeline (liquid drop-out) when the pipe wall in an aboveground pipeline drops below approximately -22 °F in conjunction with a pressure drop below the threshold where single-phase gas becomes a two-phase, gas-liquid combination.

- Because winter ambient temperatures as low as -70 °F are anticipated, in an aboveground pipeline case the Project would need to both restrict shut down and restart operations to prevent liquid drop-out, and create complex start up procedures for both the pipeline and the facilities to address the condensed liquid.

- The increased operational complexity to prevent hydrocarbon liquid drop-out would negatively impact LNG production when compared to the belowground pipeline design for the following reasons:

    - During GTP winter shutdown scenarios (planned or unplanned), the LNG Plant would continue to draw down gas into the Mainline. When the pressure falls below the critical threshold and the ambient air temperature is -22 °F or below, hydrocarbon liquids would drop out into the Mainline.

  - Subsequently during GTP winter restart scenarios, the gas pressure would be low at the beginning of the restart, and – when coupled with the low ambient temperature in the winter (below -22 °F) – additional hydrocarbon liquids would drop out during Mainline packing (pressurization up to normal operating pressures).

  - During winter shutdown and restart scenarios, pressure in the Mainline would also decrease as gas continues to be delivered to the interconnection points. This additional pressure reduction would further complicate the operational procedures for an aboveground pipeline case.

  - For the scenarios listed, any hydrocarbon liquid drop-out results in an extended shutdown to mitigate the risk of restarting a large-diameter pipeline with liquids, plus the additional facilities and logistics of the disposal of the condensed liquids.

  - Loss of LNG production equates to loss of revenue for both the State of Alaska and the Project.

  - Flow simulations indicate the possibility for thousands of barrels of hydrocarbon liquid drop-out in the scenarios listed. Additional facilities (and an increased footprint) and procedures would be needed to remove, handle, and manage the liquids. The proposed compressor station design as presented in this filing is only designed to handle minimal hydrocarbon liquid.

Line Pipe Technology

- The aboveground design is considered an advanced technology that requires a more stringent steel qualification and quality assurance programs at the mills before it can be approved for use.

- Design codes require the line pipe to exhibit good ductility (resistance to fracturing) at the operating temperatures that may be encountered during pipeline operation. In the case of an aboveground pipeline, a design temperature of -50 °F would be required due to the historical Arctic, winter air ambient temperatures.

- A limited number of worldwide line pipe manufacturers are capable of meeting the Project’s belowground requirements for pipe grade, dimensions, and properties for line pipe. This list is further restricted when the additional, ultra-low temperature requirements for aboveground pipe are added.

- Material costs for aboveground line pipe are higher due to the limited number of suppliers that are capable of providing pipe with the advanced metallurgy required to achieve the necessary toughness for ultra-low temperature use.

Environmental and Social

- Either option would result in a new linear corridor, with long-term visual impacts, especially in forested areas. The aboveground option would have greater visual impacts due to the presence of an elevated pipeline structure that would not blend into the existing viewshed within the corridor.

- Either option could result in habitat fragmentation due to ROW clearing and maintenance. Elevation of the pipeline a sufficient elevation above the ground surface would reduce impacts to large animal movements in the corridor.

- In either case, the cleared ROW could allow access to new, previously inaccessible areas for sport or subsistence hunting. This could affect wildlife populations and cause interference with existing subsistence harvests. There would likely be some areas of restricted access for an aboveground design because of safety or operational concerns. In areas with no restriction, elevating the pipeline to a sufficient height aboveground surface would reduce barriers to any all-terrain vehicle or snowmachine travel.

Based on the concerns related to increased safety and security risks, increased operational reliability risks, requirement for advanced line pipe metallurgy technologies, increased visual impacts, and greater construction cost, the belowground design was selected as the Applicants' proposed alternative.

10.4.5.1.2 PTTL

The Project also evaluated an aboveground versus belowground design mode for the PTTL and changed the pre-front-end engineering design (pre-FEED) basis to an aboveground design. Many of the comparisons made in Table 10.4.5-1 for the Mainline are also applicable to the PTTL; however, there are key technical differences that allow for an aboveground PTTL design. These technical differences are summarized in Table 10.4.5-2.

TABLE 10.4.5-2

Comparison of Mainline versus PTTL Pipeline Design (Aboveground versus Belowground)

Parameter/ Consideration	Mainline	PTTL	Comment
Interconnection Points--Provision of gas interconnection points for in-state gas supply and connection with LNG facility	Yes	No	State and LNG gas interconnection points are a key factor to enabling hydrocarbon liquid drop-out (pressure drops below critical pressure level at which single-phase gas can transition to two-phase gas-liquid). The PTTL does not have pressure drop issues because there are no interconnection points, and if the GTP shuts down, gas would not be withdrawn from the PTTL.
Gas Chilling	Yes – cooled to below 32 °F	No – gas enters PTTL at 75 °F	The PTU facility design does not include a gas cooling process and equipment. The gas exiting the PTU facility and into the PTTL would be 75 °F and would melt the permafrost. This is not conducive for a belowground design.

TABLE 10.4.5-2

Comparison of Mainline versus PTTL Pipeline Design (Aboveground versus Belowground)

Parameter/ Consideration	**Mainline**	**PTTL**	**Comment**
Elevation Profile	Upward incline; 1,000 feet of elevation change	Relatively flat; minimal elevation change	If liquids drop out (unlikely for the PTTL), the Mainline profile is conducive to liquid pooling and slugging while the PTTL is relatively flat.
Liquid Handling	Standard compressor station; liquids handling is minimal for below ground. Larger footprint required for above ground to remove and store liquids.	Slug catcher is the standard design at GTP – liquids handling is adequate.	The GTP's slug catcher is designed to manage any PTTL hydrocarbon liquid scenarios so there are no issues with aboveground design liquid dropout. The compressor stations along the Mainline route are designed for only minimal liquid handling, and then the liquids would need to be handled and transported somewhere, further complicating operational procedures. Unlike the Mainline design, the PTTL does not have any compressor stations as part of the pipeline system.
Maximum Allowable Operating Pressure (MAOP)	2,075 pounds per square inch gauge (psig)	1,150 psig	Mainline aboveground pipe parameters would require step-out technology and a more stringent line pipe qualification program due to the combination of high MAOP, large diameter, low temperature, and weight. The PTTL aboveground pipe specifications are proven. The Mainline aboveground design is considered an advanced technology that requires a more-stringent steel qualification program at the mills before it can be approved for use due to the combination of high pressure (2,075 psig), large diameter (42 inches), and low temperature steel properties (-50 °F design). The PTTL aboveground specifications, specifically the MAOP and diameter, are less than the Mainline and are proven line pipe technology.
Diameter	42 inches	32 inches	
Minimum Design Metal Temperature	-50 °F if aboveground +5 °F if belowground	-50 °F	

As noted in Table 10.4.5-2, there are key technical design differences that led to a decision for the PTTL to be an aboveground pipeline design—most notably, the PTTL system does not have the operational reliability and line pipe technology issues described in Section 10.4.5.1 Mainline, and the PTTL gas is a warm product that would destabilize the permafrost across the pipeline route.

Operational Reliability and Feasibility:

- Hydrocarbon liquid drop-out only occurs when gas in an aboveground pipeline is subjected to Arctic ambient air temperatures and the gas temperature drops below approximately -22 °F in conjunction with a pressure drop below the threshold where single-phase gas becomes a two-phase, gas-liquid combination;

- The PTTL would not have complex operational procedures to maintain gas pressure because there are no state interconnection points (which reduce mainline pressure) and if the PTU facility shuts down the GTP would not continue withdrawing gas from the PTTL, therefore there would be no pressure drop;

- In the event hydrocarbon liquids did drop out within the PTTL, the GTP facility's slug catcher is designed and to handle and manage that relatively small amount of liquids (compared with Mainline liquid volumes scenarios); and
- PTTL operational procedures are not impacted or further complicated by a potential liquid drop-out scenario given the GTP design.

Line Pipe Technology:

- The PTTL aboveground line pipe specifications are different from the Mainline aboveground specifications; and
- The lower MAOP and smaller diameter for the PTTL are proven technology, and a number of worldwide line pipe manufacturers are capable of meeting the Project's requirements.

Environmental and Social:

- Either option would result in a new linear corridor, with long-term visual impacts;
- The PTTL aboveground option would closely parallel existing aboveground pipeline infrastructure; and
- PTTL gas is a warm product that would destabilize the permafrost across the pipeline route if a belowground design would be chosen.

For the PTTL aboveground design, there are no increased operational reliability risks; the line pipe metallurgy technologies are proven, and the aboveground line parallels existing aboveground pipeline infrastructure. In addition, the warm gas from the PTU facility would destabilize the permafrost across the pipeline route. Because of these key technical reasons, the aboveground design was selected as the Applicants' proposed alternative.

10.4.6 Pipeline Diameter Alternatives

Pipeline throughput is a function of line diameter, operating pressure, and the magnitude and spacing of compression. There are many combinations of these variables that would yield a desired throughput, but all of the Project components must be matched from a throughput perspective to minimize the unit cost of delivery.

The Applicant evaluated alternatives to determine the most cost-effective pipeline system to deliver Mainline gas volumes ranging from 1.8 to 5 billion cubic feet per day to the LNG Plant to evaluate several LNG train configuration and capacities. The scenarios evaluated included 60 combinations using:

- Four pipeline diameters (36-, 42-, 44- or 48-inch);

- Three maximum operating pressures (1,940, 2,075, or 2,500 pounds per square inch gauge [psig]); and
- Five compression scenarios (1, 4, 8, 13 or 18 single-unit stations).

The analysis included 1) cost estimates for various line sizes and hydraulic options and 2) a calculation of the unit cost of delivery for the various options. Costs relate to not only construction of different line sizes but also the fuel and operating costs depending upon the number of compressor stations. From an environmental perspective, the differences would not be substantial enough to compare. The construction and operation widths would be similar. The impacts outlined in Resource Reports Nos. 2–8 would be similar for each pipe diameter. The only difference would be in the acreage footprint and resultant environmental impact of either fewer or greater number of compressor stations and the footprint of that impact. Because each compressor station is approximately 25–30 acres each, the difference in impacts are minor compared to the total Project footprint. Air emissions would also be tied directly to the number of compressor stations, and size and number of the compressor units. The total amount of compression required varies for each scenario; therefore, air emissions change with the different compression scenarios.

For Mainline delivery of 2.7 billion cubic feet per day (annual average), the Applicants' proposed alternative was found to be a 42-inch-diameter pipeline with 2,075 psig and compression supplied by eight stations. This alternative had the lowest unit cost of delivery and is expandable if additional gas were available in the future.

10.4.7 Mainline River Crossings

10.4.7.1 Yukon River Crossing Design

The Mainline crosses the Yukon River approximately 100 miles north of Fairbanks, which is the widest river crossing along the Mainline route. The crossing parallels the Dalton Highway and TAPS bridge crossing. The depth of the Yukon River in the vicinity of the crossing at the thalweg ranges from 20 feet to 44 feet, depending on the time of year.

Over the past 35 years, crossing methods and locations for a natural gas pipeline have been considered, including for the Alaska Northwest Gas Transportation System (ANGTS), TAGS, Pipeline Producers Team (AGPPT), Denali, APP, ASAP Project, and this Project. In the case of ANGTS and AGPPT, this included attachment to the existing pipe brackets on the west side of the existing E.L. Patton Yukon River Bridge (Yukon River Bridge). The TAPS is currently attached to pipe brackets along the east side of the bridge. These pipe brackets are controlled by the Alyeska Pipeline Service Company. To date, the Alyeska Pipeline Service Company has indicated that it will not allow a gas pipeline to be placed on the bridge, citing the firm has priority for placement of a second pipeline (ADOT&PF, 2015). This would also be its concern if a pipe were to be hung beneath the bridge.

This information was used for the present analysis and considered six crossing designs for the Yukon River (note: although the discussion is related to constructing the pipeline across the Yukon River, each method requires a different design for the pipeline itself, the workspace required to install it, and the operating requirements, including trenchless method, attachment on the existing Yukon River Bridge, and a new pipeline bridge).

Use of the open-cut method was not considered to be a viable alternative. The width of the crossing (approximately 2,200 feet) is not conducive to an open-cut installation and it would be impracticable and cost/schedule prohibitive to cut down the bluffs on the south side of the river near the existing bridge in bury the pipeline. Subsurface investigations within the river indicate a sand and granular material layer in excess of 30 feet. The unconsolidated nature of the sediments would require a very wide trench to get the pipeline down below the scour depth of the river. This fact, coupled with the high flow rates of the river, would make an open-cut crossing infeasible.

A trenchless installation would be designed to install the pipeline below the potential scour depth of a 100-year flood event. An overview of the alternative crossing methods considered is provided in Table 10.4.7-1.

The proposed Yukon River crossing is via trenchless method (i.e., HDD or DMT method, see Section 1.5.2.3.4.1 of Resource Report No. 1), approximately 3,000 feet downstream of the Yukon River Bridge. The use of a trenchless method at this location combines elements of the previous design investigations, and the proposed crossing was created using ASAP Project route revision information. In late 2014, multiple workshops were held between the Project and the ASAP Project to further refine the crossing design, including straightening the alignment for the crossing and reducing the amount of false ROW (workspace that is required outside the pipeline ROW to align with the crossing angle of the waterbody). Preliminary analysis indicates that the trenchless crossing method is feasible in this location and it was selected based on (1) a smaller construction footprint, (2) shorter construction timeframe, (3) reduced environmental impacts, including avoiding the riverbed and riparian areas, and (4) reduced operation and maintenance concerns, as compared to construction of a new bridge. Other crossing options were eliminated because they would provide no apparent environmental or operational benefits over the trenchless crossing alternative. Use of the existing Yukon River Bridge would result in risk and safety concerns, as well as impacts to a Native allotment; therefore, use of the existing bridge was not considered favorable over the trenchless crossing method (see Resource Report No. 2, Appendix I).

Additional deeper boreholes would be completed to confirm the anticipated geology for the trenchless method. If the boreholes indicate that the use of trenchless method is not feasible, crossing the Yukon River using a two-span suspension bridge would then become the proposed alternate. Although the two-span alternative requires the placement of a pier within the river, it results in a shorter crossing length than a single-span bridge. The existing TAPS pipeline suspension bridge over the Tanana River has a similar span length, providing a baseline for expected performance of a two-span suspension bridge.

TABLE 10.4.7-1

Alternative Crossing Methods of the Yukon River

Considerations		Crossing Method					
			Yukon River Bridge		New Bridge		
		Trenchless Method (Applicants' proposed alternative)	**Use of Existing, Unoccupied Pipe Supports Located on the West Side of the Bridge**	**Hanging of the Pipe Beneath the Bridge Using a Pipe Hangar Assembly**	**One-Span Suspension Bridge**	**Two-Span Suspension Bridge**	**Box Girder Bridge**
Engineering/ Technical	Access	Requires new access road	Access directly from Dalton Highway	Access directly from Dalton Highway	Requires new access road	Requires new access road	Requires new access road
	Ice Scouring	The granular bed of the Yukon River is anticipated to function as a buffer to potential scour.	Piers require protection from ice and scour	Piers require protection from ice and scour	No concern; no in-water piers	Pier would require protection from ice and scour	Piers require protection from ice and scour
	Operations and Maintenance	None	Ongoing bridge inspection and maintenance	Ongoing bridge inspection and maintenance	Ongoing bridge inspection and maintenance	Ongoing bridge inspection and maintenance	Ongoing bridge inspection and maintenance
	Risk and Safety Concerns	Preliminary analysis indicates design and trenchless installation is feasible. However, a geotechnical program is needed to provide an improved assessment of the risks associated with the trenchless method and recommendations on mitigation strategies (e.g., ice-rich soils).	Risk of vandalism, terrorism, and potential bridge failure	Risk of vandalism, terrorism, and potential bridge failure	Risk of vandalism, terrorism, and stabilizing potential ice-rich soils for foundations and anchor locations	Risk of vandalism, terrorism, and stabilizing potential ice-rich soils for foundations and anchor locations	Risk of vandalism, terrorism, and stabilizing potential ice-rich soils for foundations and anchor locations
Environmental	Land Ownership	Avoids Native allotments	Requires crossing a Native allotment in transitioning off the south end of the bridge	Requires crossing a Native allotment in transitioning off the south end of the bridge	Avoids Native allotments	Avoids Native allotments	Avoids Native allotments

TABLE 10.4.7-1

Alternative Crossing Methods of the Yukon River

Considerations		Crossing Method					
			Yukon River Bridge		New Bridge		
		Trenchless Method (Applicants' proposed alternative)	**Use of Existing, Unoccupied Pipe Supports Located on the West Side of the Bridge**	**Hanging of the Pipe Beneath the Bridge Using a Pipe Hangar Assembly**	**One-Span Suspension Bridge**	**Two-Span Suspension Bridge**	**Box Girder Bridge**
	Disturbance to Yukon River Bed	None	None	None	None	One in-stream pier is required; turbidity and sedimentation from installation	Five in-stream piers are required, turbidity and sedimentation from installation
	Wetlands/ Fisheries	Avoids both wetlands and fisheries	Impacts wetlands leading to bridge	Impacts wetlands leading to bridge	Impacts wetlands leading to bridge	Impacts wetlands leading to bridge, impacting fisheries while building pier	Impacts wetlands leading to bridge, impacting fisheries while building pier
	Cultural Resources	Avoids the cultural site by the south end of the Yukon River Bridge	The bridge is a designated cultural site.	The bridge is a designated cultural site.	Avoids the cultural site by the south end of the Yukon River Bridge	Avoids the cultural site by the south end of the Yukon River Bridge	Avoids the cultural site by the south end of the Yukon River Bridge

10.4.8 PTTL River Crossings

The PTTL would be above ground on VSMs and elevated a minimum of 7 feet except at four river crossings. The proposed design is for the pipeline to cross under the Shaviovik River, Kadleroshilik River, and Sagavanirktok River (Main Channel) using an open-cut method and over the Sagavanirktok River (West Channel) on an existing pipe bridge. The Project considered the alternative of a trenchless installation for crossing of the Shaviovik, Kadleroshilik, and Sagavanirktok rivers. The traditional open-cut method was selected based on the following:

- These rivers have been crossed by the Badami pipeline using the open-cut method and the river banks are currently stable (the Project acknowledges the challenges encountered near the East Channel of the Sagavanirktok River with the Badami pipeline);
- Any potential erosion of the river banks or draining of water bodies would be mitigated by incorporating learnings from the routing and restoration challenges at the Badami pipeline crossing of the East Channel of the Sagavanirktok River;
- These rivers are shallow and at very low flow during the winter;
- The open-cut method allows for a faster installation;
- Subsurface soil conditions at these sites are not presently known. The presence of granular material or cobbles would create steering problems for the drill path, making boreholes prone to collapse (maintaining the borehole is essential to the trenchless method operation), increase risk of drilling mud loss, and creating excessive wear on the “down hole” equipment;
- The only completed trenchless method to date on the North Slope is the Colville River Crossing on the Alpine Project and the subsurface soil conditions are likely not the same as the river crossing locations for the PTTL. Unanticipated volumes of drilling mud were lost down hole during this trenchless installation; and
- The trenchless method process is water-based, creating complications in subfreezing temperatures and in permafrost soil conditions.

The PTTL Design Crossing Report (Appendix E), provides additional information on the design approaches made in the conceptual design study at each of these crossings.

10.4.9 Pipeline Aboveground Facility Alternatives

10.4.9.1 Facility Siting

During early engineering, compressor station locations were primarily dictated by minimizing the number of stations required for Project hydraulics to meet required throughput, as well as manage Mainline temperature. Initial hydraulic modeling determined the geographical extent within which station location alternatives were to be evaluated, in the form of an ‘investigation area’. During review, engineering (e.g., geotechnical conditions at site), construction (e.g., access, avoiding existing infrastructure, and cut/fill requirements), and environmental considerations (e.g., visual and wetland impacts, emissions; see Table 10.4.9-1) were evaluated and incorporated into the final siting of each compressor station within the requisite 'investigation area'. Station locations were reviewed by a multidisciplinary team to ensure all considerations were addressed in the selection of each station location. In addition to striking a balance between environmental, engineering, and construction factors, the site selection process invariably requires a trade-off between positive and adverse impacts across different resource types. For example, an upland site may be favored because of reduced wetlands impacts, however, being on higher, drier ground may then result in the potential for increased impacts to visual resources.

TABLE 10.4.9-1

Screening Criteria for Compressor Station Evaluation Areas

Category	Criteria	Potential Considerations
Land Use/Ownership Criteria	Populated areas	Proximity to residences and planned development
	Land ownership, land use, special areas (refuges, parks, recreation areas)	Project's consistency with land use practices and management regulations/plans
	Presence of infrastructure or other industrial facilities	Compatibility with existing and future land use and potential environmental effects due to the need for new infrastructure (e.g., roads, air strips) to support construction and operation of the Project
	Known contaminated sites	Environmental effects due to constructing in contaminated soils/sediments
Facility Permitting	Emissions constraints	Terrain effects on air emissions dispersion; proximity to Class I air shed
	Water constraints	Availability issues and water rights conflicts
	Public opposition	Public concerns
Waters of the U.S.	Wetlands and Waterbodies	Avoid and minimize impacts
Fisheries, Wildlife and Protected Species	ESA critical habitat and other valuable habitat	Constraints upon construction activities and facility operations
	Anadromous streams	
	Significant wildlife habitats; raptor nests	
Cultural Resources	Known cultural resources areas	Constraints upon construction activities and facility operations
Geological Hazards	Fault lines, landslides	Construction and operation hazards, design considerations, and sustainability of the proposed new infrastructure
	Landslide potential	
Stakeholders	Conflict with subsistence uses (e.g., restricted access)	Constraints on Project construction and operations due to potential incompatibility with the current use of the site and surrounding area for subsistence and recreational uses.
	Conflict with local recreational facilities/opportunities (e.g., restricted access)	
Community Impact	Avoid communities and Villages with Project development	Site aboveground facilities away from Villages and communities to avoid conflicts with roads, resource use, and subsistence use areas.
	Lighting and visual constraints	Visual resource impacts
	Noise constraints	Proximity to Noise-Sensitive Areas

A description of the siting of specific stations is provided below.

10.4.9.1.1 Galbraith Lake Compressor Station

The Galbraith Lake Compressor Station site (MP 148.56) would be located approximately 120 feet west of the Dalton Highway in an area that avoids high-gradient drainages. The Galbraith Lake Compressor Station location was shifted south-southeast from its original location near MP 145, as that location was determined to be in the path of two high-gradient drainages that carry run-off from the nearby mountains to the east. These types of drainages have the potential to cause flooding and/or avalanche hazard, particularly during spring breakup. The Galbraith Lake Compressor Station site consists of State of Alaska DNR and BLM lands. There are no known viable alternatives to the proposed Galbraith Lake Compressor Station location within the designated hydraulic design investigation area. Other alternatives would result in potentially greater wetland impacts or not avoid identified ice features.

10.4.9.1.2 Coldfoot Compressor Station

The Coldfoot Compressor Station site (MP 240.10) would be located approximately 900 feet east of the Dalton Highway on flat, sparsely wooded terrain south of Clara Creek. The Coldfoot Compressor Station site consists of State of Alaska DNR land and is mostly wetlands. The site is approximately 1.0-mile north of the nearest building in Coldfoot, with the nearest Noise Sensitive Area (NSA) located approximately 5,525 feet to the south-southwest. There are no known viable alternatives to the proposed Coldfoot Compressor Station location within the designated hydraulic design investigation area that could avoid wetlands. Other alternatives would result in impacts to NSAs to the south or impacts to Clara Creek and wetlands to the north.

10.4.9.1.3 Ray River Compressor Station

The Ray River Compressor Station site (MP 332.64) would be adjacent to the west side of the Dalton Highway, on BLM land. The location of the station was shifted south, approximately 1,720 feet, to reduce encroachment on what has been identified as terrain that would degrade (thermally) over time after site preparation and construction. The Ray River Compressor Station would be located on flat, wooded upland (no wetlands) terrain. There are no known viable alternatives to the proposed Ray River Compressor Station location within the designated hydraulic design investigation area. Other alternatives that shift the site to either the north or south would result in wetland impacts.

10.4.9.1.4 Healy Compressor Station

The Healy Compressor Station site (MP 517.62) would be located on an upper level river terrace between the Parks Highway and Nenana River, approximately 950 feet east of the highway. The location of the station was shifted approximately 400 feet northeast to avoid encroachment on an electrical transmission line easement, while also avoiding a local drainage channel. The Healy Compressor Station would be located on State of Alaska DNR land. The site is partially comprised of wetlands, with impacts to wetlands being unavoidable within the designated hydraulic design investigation area. Buildings have been identified approximately 0.65-mile to the northwest and 1.2 miles to the southwest of the site. There are no known viable alternatives to the proposed Healy Compressor Station location within the designated hydraulic design investigation area. Other alternatives would result in either moving the station closer to NSAs within the area or impacting the electrical transmission line easement to the west.

10.4.9.1.5 Alternative Station Sites

Based on a hydraulic evaluation of Route Revision C of the Mainline, the proposed Rabideaux Creek Compressor Station (MP 675.23) could be moved to an alternative Deshka River location (MP 704).

However, due to construction execution considerations and potential environmental impacts, resulting from the need for a relatively long permanent access road to the alternative Deshka River location, the Project selected the Rabideaux Creek Compressor Station site as the proposed location. As planned, the section of the Mainline where the Rabideaux Creek Compressor Station is located would be constructed during the winter to minimize disturbance to wetlands and anadromous streams. The Rabideaux Creek Compressor Station location would also result in a lower volume of gravel needed for permanent road construction, reduced road maintenance activity, and a shorter transportation route (by over 20 miles).

10.4.9.2 Mainline Block Valves (MLBVs)

MLBVs would be located at each compressor and/or heater station site, and between stations with a maximum spacing of 20 miles between valves (Class 1 Locations—see footnote 17). Along Glitter Gulch and the Kenai Peninsula where Class 2/3 Locations are encountered, additional valves have been sited in accordance with regulatory requirements. Preliminarily identified MLBV sites that were located outside of a compressor station or heater station were subjected to an evaluation similar to the one described for stations of relevant environmental, land ownership, socioeconomic, and regulatory concerns, as were the compressor stations (see description above and Table 10.4.9-1). In the case of intermediate MLBVs not collocated on compressor and heater stations sites, the Applicant initially evaluated a 1-acre study centered on the MP identified for placement of a MLBV. The proposed design of each intermediate MLBV encompasses approximately 0.37 acre, including the associated helipad that would be located adjacent to the valve. Some of the initially identified MLBV sites were shifted based on these evaluations and then based on adoption of the proposed Route Revision C2.

10.4.9.3 Electric-Motor-Driven Compressor Stations

The Applicant is currently evaluating the feasibility of using electric-motor-driven compressors at the compressor stations, as well as the feasibility of using electric power from the existing power transmission and distribution network to feed power demand at the pipeline facilities. The following information is the initial study that has been completed. As part of the evaluation, the Applicants, in coordination with local electrical power providers, would review:

- Existing electrical power supply infrastructure, including: electrical power generation, transmission and distribution infrastructure, available capacities, and current peak loads;
- Future upgrades planned prior to Project commissioning;
- Potential for upgrades (if required) to supply electrical power to the proposed facilities, and associated impacts of those upgrades;
- Routing of additional electrical power supply lines to the proposed facilities, potential tie-in points, and additional substation requirements;
- Cost of new infrastructure and cost of potential upgrades to the existing infrastructure;
- Cost of electrical power; and
- Reliability of existing electrical power supply infrastructure.

Based on their proximity to the existing electrical power supply infrastructure, three compressor stations with potential to use electric-motor-driven compressors have been identified: Healy Compressor Station

(MP 517.62), Honolulu Creek Compressor Station (MP 597.36), and Rabideaux Creek Compressor Station (MP 675.23) (Table 10.4.9-2).

TABLE 10.4.9-2

Potential Electric Power Supply for the Compressor and Heater Stations

Station	MP	Power Demand (MW)		Power Substation		Power Supply Line		
		Electric Driver	Auxiliary Power Purchase	Location	Approximate Plot Size[a]	Length (mile)	Pole Spacing (feet)	
							Electric-Motor-Driven Compressors	Station Utilities
Healy Compressor Station	517.62	25.9	1.4	Adjacent to the station	2.66	< 0.1	138 kilovolt (kV): 125 feet	25 kV: 40 feet
Honolulu Creek Compressor Station	597.36	24.2	1.0	Adjacent to the station	2.66	0.3	138 kV: 125 feet	138 kV: 125 feet
Rabideaux Creek Compressor Station	675.23	25.6	1.1	Adjacent to the station	4.79	8.5	34.5 kV: 40 feet	25 kV: 40 feet

[a] Tie-in is located within the footprint

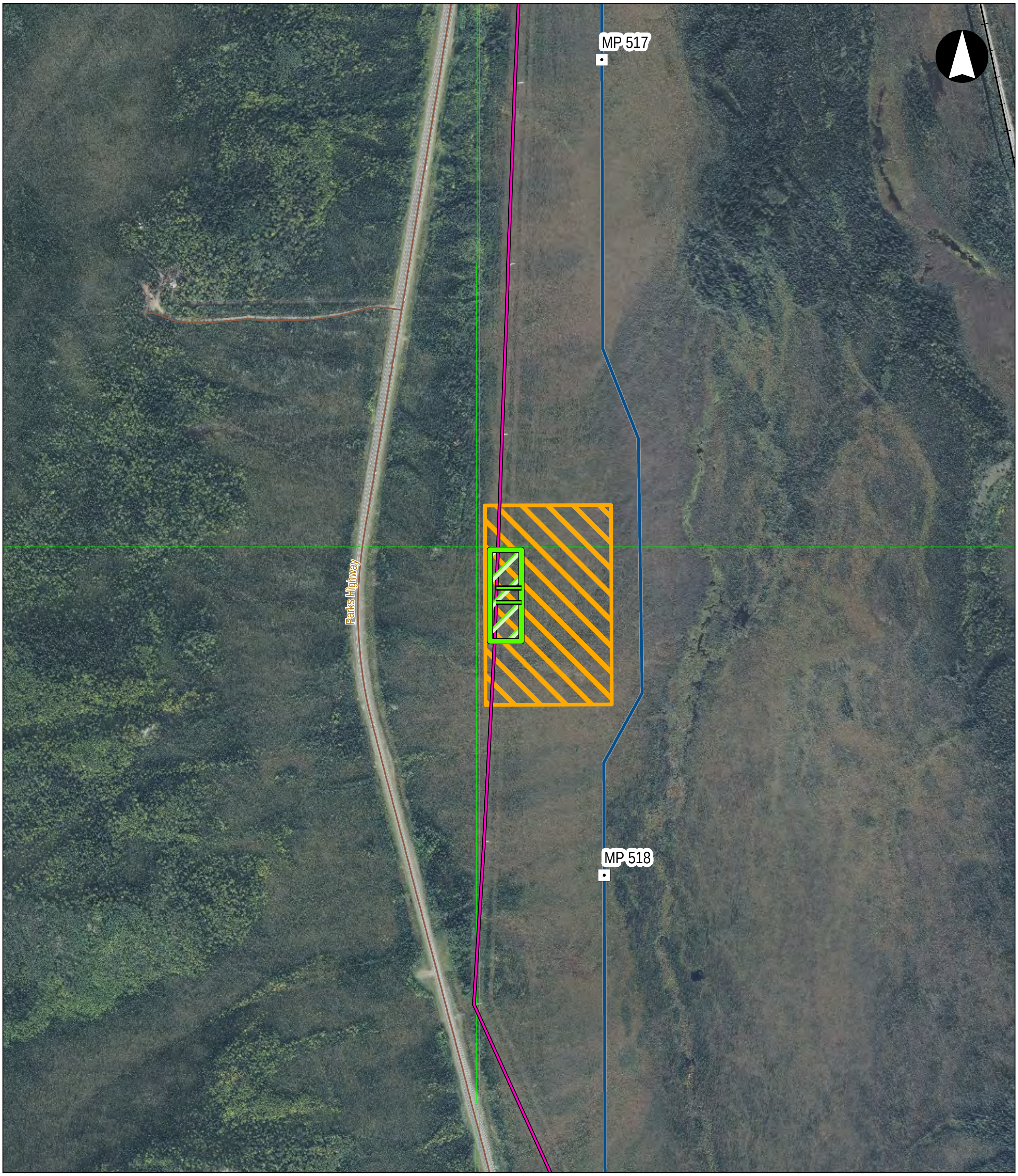
To use electricity from an outside source, each of these stations would likely require:

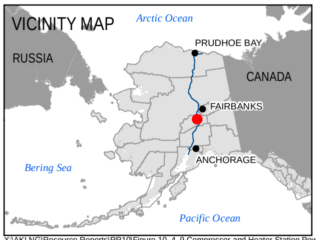
- One pipeline compressor with electric motor;
- Variable frequency drive;
- Associated electrical equipment and infrastructure at the compressor station;
- A new 230 kV/34.5 kV electrical substation facility; and
- A new overhead electrical power distribution line from the nearest electrical grid connection.

The three compressor stations also have the potential to use electric power to feed station utilities (Table 10.4.9-2). Opportunity to feed auxiliary power demand from the grid would reduce the requirement for onsite power generation thereby limiting it to one onsite backup power generator. The rest of the station equipment would remain similar to the proposed case with onsite power generation.

New overhead electrical power lines would need to be constructed to supply electricity to the stations. Preliminary routing studies have determined that the length of the required power supply lines would be:

- Approximately <0.1 mile of 25 kV and 138 kV power supply lines for the Healy Compressor Station (Figure 10.4.9-1) from the Golden Valley Electric Association (GVEA) powerline;
- Approximately 0.3 mile of 138 kV power supply lines for the Honolulu Creek Compressor Station (Figure 10.4.9-2) from the GVEA powerline; and
- Approximately 8.5 miles of 25 kV and 34.5 kV power supply lines for the Rabideaux Creek Compressor Station (Figure 10.4.9-3) from the Matanuska Electric Association (MEA) powerline.





X:\AKLNG\Resource Reports\RR10\Figure 10_4_9 Compressor and Heater Station Power Supply Lines.mxd

LEGEND

- Rev C2 Mile Post
- Alaska LNG Rev C2 Route
- Powerline Tie-In
- Golden Valley Electric Association Powerline
- Roads
- Railroad
- Compressor/Heater Station - Rev C2
- Substation

0 0.05 0.1 0.2 Miles

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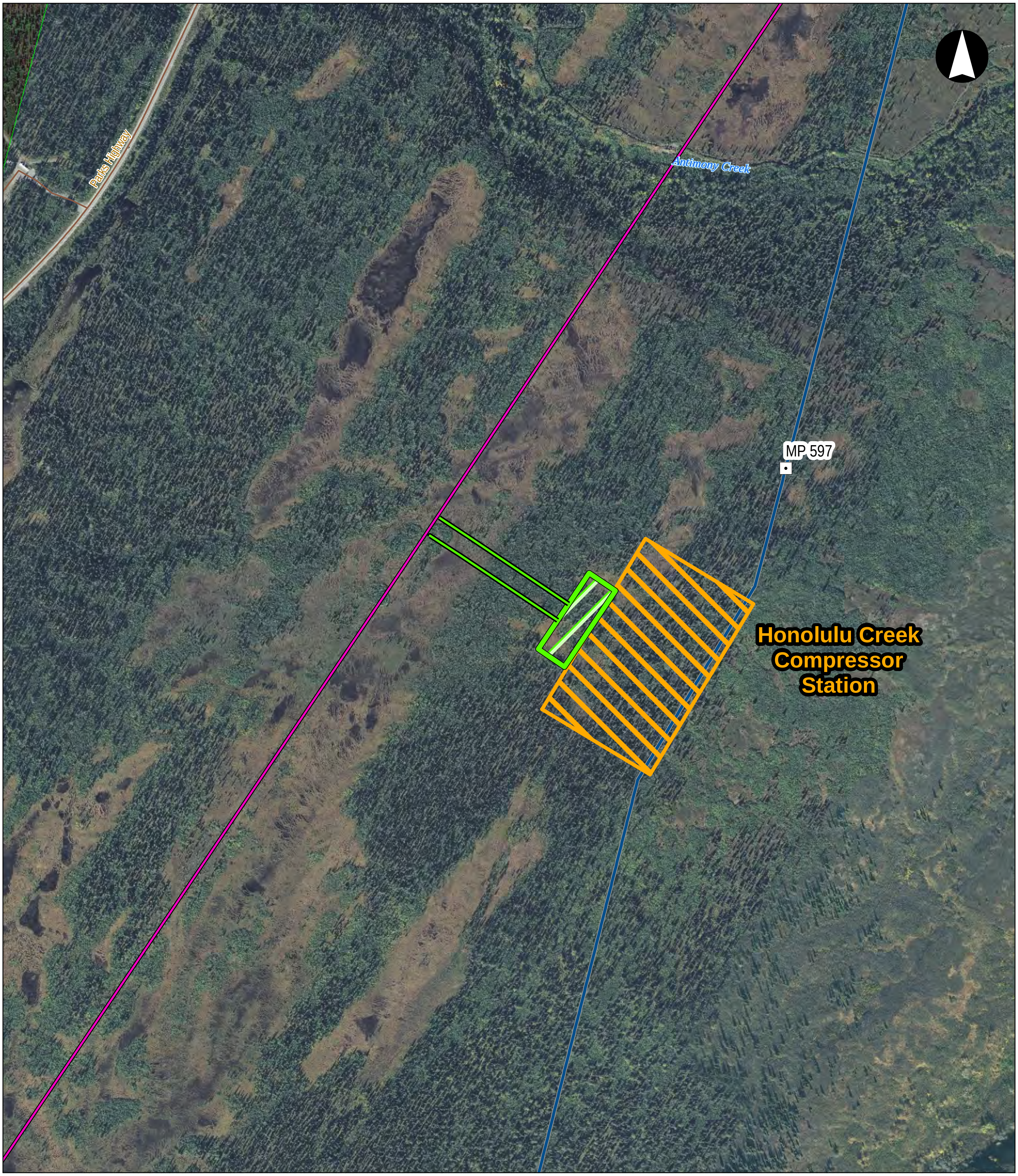
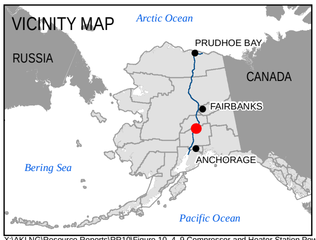
COMPRESSOR STATION POWER SUPPLY LINES HEALY

FIGURE 10.4.9-1

ALASKA LNG





LEGEND

- Rev C2 Mile Post
- Alaska LNG Rev C2 Route
- Powerline Tie-In
- Golden Valley Electric Association Powerline
- Roads
- Compressor/Heater Station - Rev C2
- Substation

0 0.05 0.1 0.2 Miles

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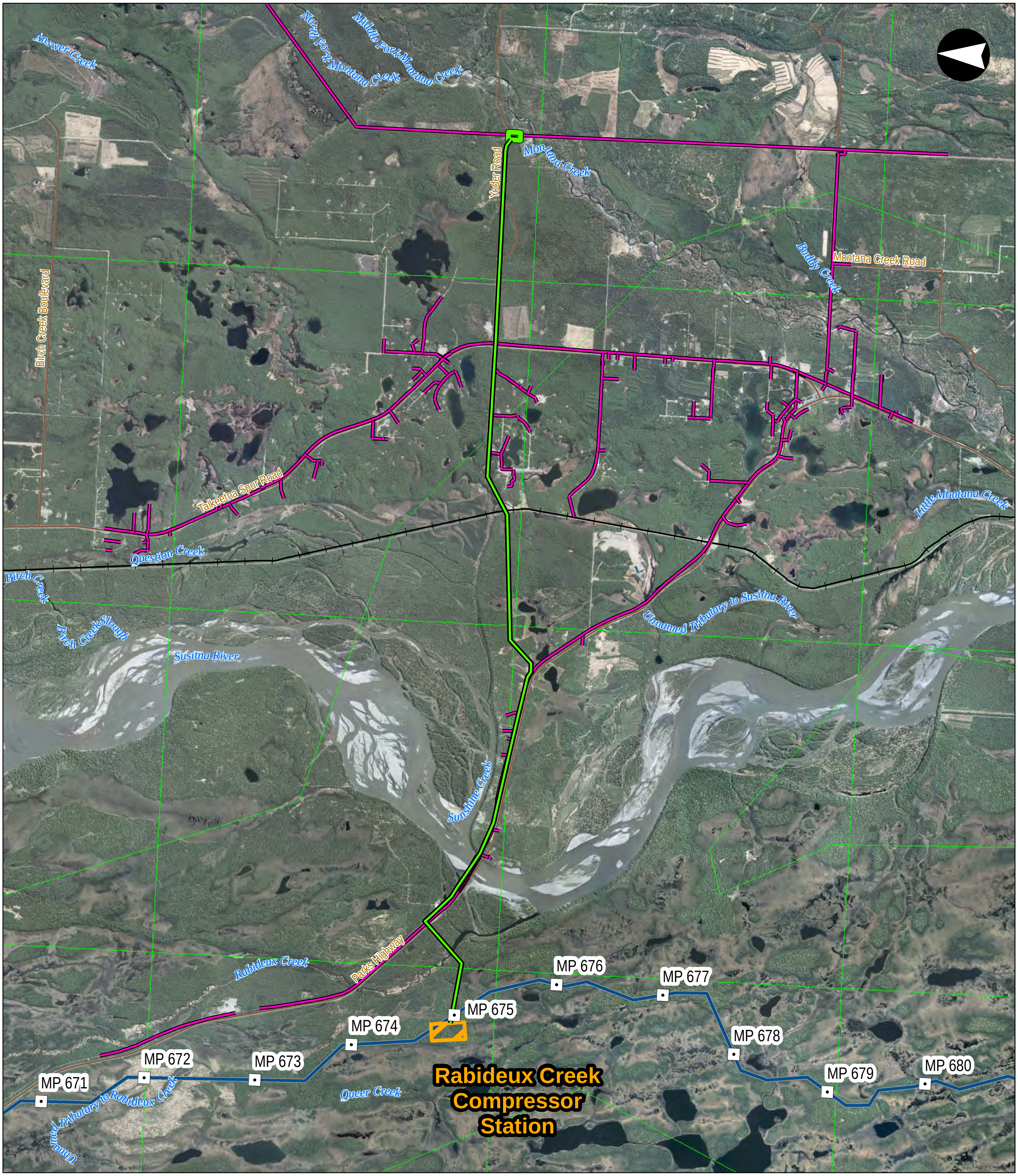
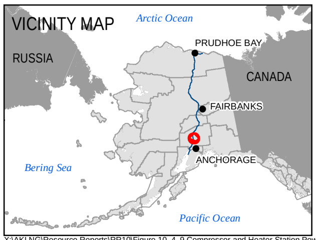
COMPRESSOR STATION
POWER SUPPLY LINES
HONOLULU CREEK

FIGURE 10.4.9-2

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_4_9 Compressor and Heater Station Power Supply Lines.mxd





LEGEND

- Rev C2 Mile Post
- Alaska LNG Rev C2 Route
- Powerline Tie-In
- Matanuska Electric Association Powerlines
- Roads
- Railroad
- Compressor/Heater Station - Rev C2
- Substation

0 0.45 0.9 1.8 Miles

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COMPRESSOR STATION POWER SUPPLY LINES RABIDEUX CREEK

FIGURE 10.4.9-3

ALASKA LNG

X:\AKLNG\Resource Reports\RR10\Figure 10_4_9 Compressor and Heater Station Power Supply Lines.mxd

The voltage rating of these power supply lines would be either 25 kV, 34.5 kV, or 230 kV and would depend on the location of the step-down substation. Connection of the other Project facilities to the electrical power supply grid would involve construction of longer power transmission or distribution lines, making electric power supply option infeasible (uneconomical).

As noted previously, all three stations would be connected to either the existing 25 kV power distribution lines, or to the Alaska Intertie transmission line, and would fall into service areas of the two power providers, GVEA (for the Healy and Honolulu Creek compressor stations) and MEA (connection to the Alaska Intertie power transmission line for the Rabideaux Creek Compressor Station).

New 230 kV/34.5 kV electrical substation facilities would need to be built, which would include circuit breakers, motor-operated switches, surge arresters, a step-down transformer, control building, and associated civil and structural works, fencing, and access roads.

Where the connection would be made to the existing distribution power lines, the tie-in substation would be significantly smaller and would include a circuit breaker, an air break switch, surge arresters, a control enclosure, and associated civil and structural works, fencing, and access roads.

Preliminary results of the evaluation indicate that an upgrade of the existing MEA power plant would be required to supply power to the Rabideaux Creek Compressor Station to use electric-motor-driven compressors, while power could be supplied by GVEA to the other two stations to use electric-motor-driven compressors without any required expansion of the existing power plants. In addition, preliminary results of the evaluation also indicate that upgrades would not be required to the existing power plants to feed any of the three stations (i.e., all three compressor stations) for the purpose of auxiliary loads (i.e., feed station utilities).

Connection to the new power supply lines would result in creating a new approximate 0.1 to 8.7-mile corridor depending upon the compressor station that would be connected to the electric power grid. This would result in the need for vegetation clearing for line construction, as well as ongoing maintenance of a tree-free, permanent ROW. In addition, vegetation clearing would be required for installation of the power substations, either adjacent to the station footprint, or located near the power source. An overview of the potential environmental resources that would be impacted by each alternative is provided in Table 10.4.9-3.

TABLE 10.4.9-3

Environmental Considerations for Potential Electrical Supply Alternatives

	Power Supply Line and Power Substation Footprint		
Criteria	**Healy Compressor Station**	**Honolulu Creek Compressor Station**	**Rabideaux Creek Compressor Station**
Land Use	Solely on State of Alaska land	Solely on State of Alaska land	The power supply line traverses private land and lands that are part of a State Resource Sale Area (timber). The power substation footprint is within three parcels, of which one is owned by a Native Corporation and one is owned by the State of Alaska.[c]

TABLE 10.4.9-3

Environmental Considerations for Potential Electrical Supply Alternatives

	Power Supply Line and Power Substation Footprint		
Criteria	**Healy Compressor Station**	**Honolulu Creek Compressor Station**	**Rabideaux Creek Compressor Station**
Wetlands[a]	100 percent wetlands	Approximately 13 percent of the power supply line crosses wetlands; approximately 22 percent of the substation crosses wetlands[b]	Approximately 5 percent of the power supply line crosses wetlands; approximately 40 percent of the substation crosses wetlands[b]
Waterbodies	No streams crossed	No streams crossed	The power supply line crosses four streams (Susitna River, Rabideaux Creek [twice], and a tributary of Sunshine Creek), all of which are anadromous. It is assumed that with the exception of the Susitna River, these streams could be spanned and no structures would be placed in the stream channel.
Significant wildlife habitat	None identified	None identified	None identified[c]
Cultural Resources (500 feet)	None identified	None identified[c]	The buffer of one known cultural site is located along the power supply line's centerline; however, the site is an existing, habited residential structure that has been determined Not Eligible for Listing on the National Registry of Historic Places.[c]
Potential Contamination[a]	None identified	None identified	Three contaminated sites are known to occur within 0.5 mile of the power supply centerline with the closest being at 0.1 mile. One is deemed Open, one is deemed Closed, and the third is a retired landfill

[a] The power supply line would be suspended on poles, minimizing subsurface disturbance.
[b] Incomplete field survey coverage to date, data supplemented by NWI data.
[c] Incomplete field survey or land use coverage to date

The Applicant is currently working to develop life-cycle cost estimates and construction schedules, and are evaluating availability, reliability, and maintainability of the electric facilities. These details will feed into the recommendation on the type of power supply for the three stations.

10.4.10 Emission Control Technologies

While not subject to major source or PSD permitting, all of the compressor stations, assuming they are gas or electric driven, are minor sources of air pollution and would be subject to minor source permitting by ADEC. Because they are minor sources and do not represent significant contributors to air quality degradation, alternative air emission control technologies are not considered in the review the minor source permitting process. The heater station may not be subject to any permitting from ADEC because the proposed emissions from this station are below the minor source permitting threshold established by ADEC regulations.

Notwithstanding the permitting status of the compressor and heater stations, the Applicant has carefully considered the design of practical emission controls for the compressor and heater stations. The main gas compressors would be designed with low nitrogen oxide (NO_x) combustion controls (i.e., Dry Low NO_x or DLN). Heaters would be equipped with low NO_x burners. Internal combustion engines at each station would be equipped with catalytic controls to meet stringent emission limits established by the Clean Air Act New Source Performance Standards.

10.5 GTP ALTERNATIVES

In determining the potential site locations for the GTP, the Applicant first conducted a regional analysis on the North Slope, and subsequently performed an evaluation of site alternatives within the selected region. Locating the GTP at an LNG facility in southcentral Alaska was also evaluated but a detailed analysis was not considered further because of the impracticalities of siting a high-pressure untreated gas pipeline along primary road infrastructure that is critical to the state, as well as the inability to inject the byproducts into geological formations in the Nikiski area. Locating the GTP at a LNG facility in southcentral Alaska was eliminated from further consideration for the following reasons:

- Increased emissions along the Mainline due to higher fuel usage for compression, and fuel gas potentially containing hydrogen sulfide (H_2S);
- Higher risks associated with a leak from the Mainline due to the potential presence of H_2S in the gas. Spacing between the pipeline and any residential or community development would need to consider wind speed and direction, as well as evacuation routes and the ability to quickly move people from an area if a rupture or leak occurred;
- Loss of ability to supply the GTP Byproduct stream (primarily CO_2) to the PBU for its use;
- No reasonable or practicable alternative to use the GTP Byproduct stream for oil field-enhanced recovery. The existing oil fields near the Nikiski site are not large enough to handle the volumes of byproduct, nor do they have the oil reserves remaining that require a 30-year supply of byproduct; and
- In-state deliveries of natural gas would require extensive treatment facilities as part of any third-party gas interconnection point facilities to remove byproducts and have the ability to store and transport those byproducts for disposal. This would also make it more difficult to meet the Project's purpose.

10.5.1 Methodology, Constraints, and Rationale for the GTP Alternative Evaluation

A North Slope regional analysis was first conducted based on identifying study areas that met the following criteria:

- Minimize distance to the expected point of GTP Byproduct stream receipt facilities;
- Safety distance from existing operating facilities;
- Minimize environmental impacts; and
- Use existing infrastructure to the extent possible.

Following the regional analysis described in Section 10.5.2, a second analysis was conducted looking at potential alternative sites within the proposed region, approximately 300 acres in size, as discussed in Section 10.5.3.

10.5.2 Study Area Alternatives for the GTP

Four geographical study areas were evaluated, each approximately over 20 miles wide (refer to Figure 10.5.2-1):

- PBU – In the vicinity of the developed area of the PBU, including Deadhorse;
- West of PBU – Beginning outside the developed area of the PBU and extending westward. The western boundary of this area is not specifically defined;
- South of PBU – Beginning south of Deadhorse and extending southward. The southern boundary of this area is the Brooks Range; and
- East of PBU – Beginning outside the developed area of the PBU and extending eastward. The eastern boundary is defined by the Arctic NWR.

Each study area was then compared to see which area fulfilled more criteria necessary for siting a major industrial facility and had the fewest environmental constraints present in the study area. Table 10.5.2-1 summarizes the results of this comparison and identifies which study area(s) fulfilled the objectives identified in 10.5.1.

TABLE 10.5.2-1

Study Areas Evaluated for GTP Siting

Criteria			**PBU (Applicants' Proposed Alternative)**	**East of PBU**	**South of PBU**	**West of PBU**
Engineering/Technical Considerations	Minimize distance to feed gas source (PBU Central Gas Facility [CGF] and/or PTU)		Yes	Yes	No	No
	Minimize distance to byproduct stream receipt facilities		Yes	No	No	No
	Proper safety distance from existing operating facilities and public/private infrastructure		Yes	Yes	Yes	Yes
	Near existing resources/services for both construction and operation use		Yes	No	No	No
Environmental	Footprint (i.e., near existing infrastructure that could be used by the Project)		Yes	No	No	No
	Land Use[a]	Wetland/Open Water (non-marine) (Percent of Area)[b]	95.9	97.4	99.9	99.7
		Developed (Low/Medium Intensity) (Percent of Area)	3.1	<1	<1	<1
		Barren Land (Percent of Area)	7.8	4.6	7.8	1.5
		Perennial Ice/Snow (Percent of Area)	1.7	0	0	<1
		Vegetated (shrub, scrub) (Percent of Area)	<1	1.3	<1	<1
		Vegetated (sedge, herbaceous) (Percent of Area)	38.9	44.9	65.2	67
		Number of existing roads (including private access roads	58	1	2	1
	Number of Residential Areas/Communities [c]		0	0	0	0
	Air Quality	Class I Area	488 miles to closest Class I Area (DNPP)[d]	481 Miles to closest Class I Area (DNPP)[d]	474 Miles to closest Class I Area (DNPP)[d]	482 Miles to closest Class I Area (DNPP)[d]
	Number of Previously Identified Potentially Eligible Cultural Sites in the Area[e]		25	25	7	55
	Number of Known Potential	Solid Waste Site	3	1	0	8
		LUST Site	1	0	1	0

TABLE 10.5.2-1

Study Areas Evaluated for GTP Siting

Criteria			**PBU (Applicants' Proposed Alternative)**	**East of PBU**	**South of PBU**	**West of PBU**
	Contamination Sources[f]	Site under active management, closed, or closed with institutional controls	115[g]	4	21	52
	Critical Habitat for ESA Species		None (75 percent within proposed Polar Bear Critical Habitat) [h]	None (72 percent within proposed Polar Bear Critical Habitat)	None	None (27 percent within proposed Polar Bear Critical Habitat)

[a] National Land Cover Database, percentages of are based on total land area and do not include unclassified marine areas

[b] NWI data is used instead of the more generalized National Land Cover database mapping that is not accurate at the scale of the analysis.

[c] There are no communities or residences in this part of the North Slope. There are camps and industrial facilities with housing that are scattered throughout the developed areas.

[d] Distance from the center of the geographic area to the center of the wilderness area. None of the wilderness areas fell within the boundaries of the geographic areas.

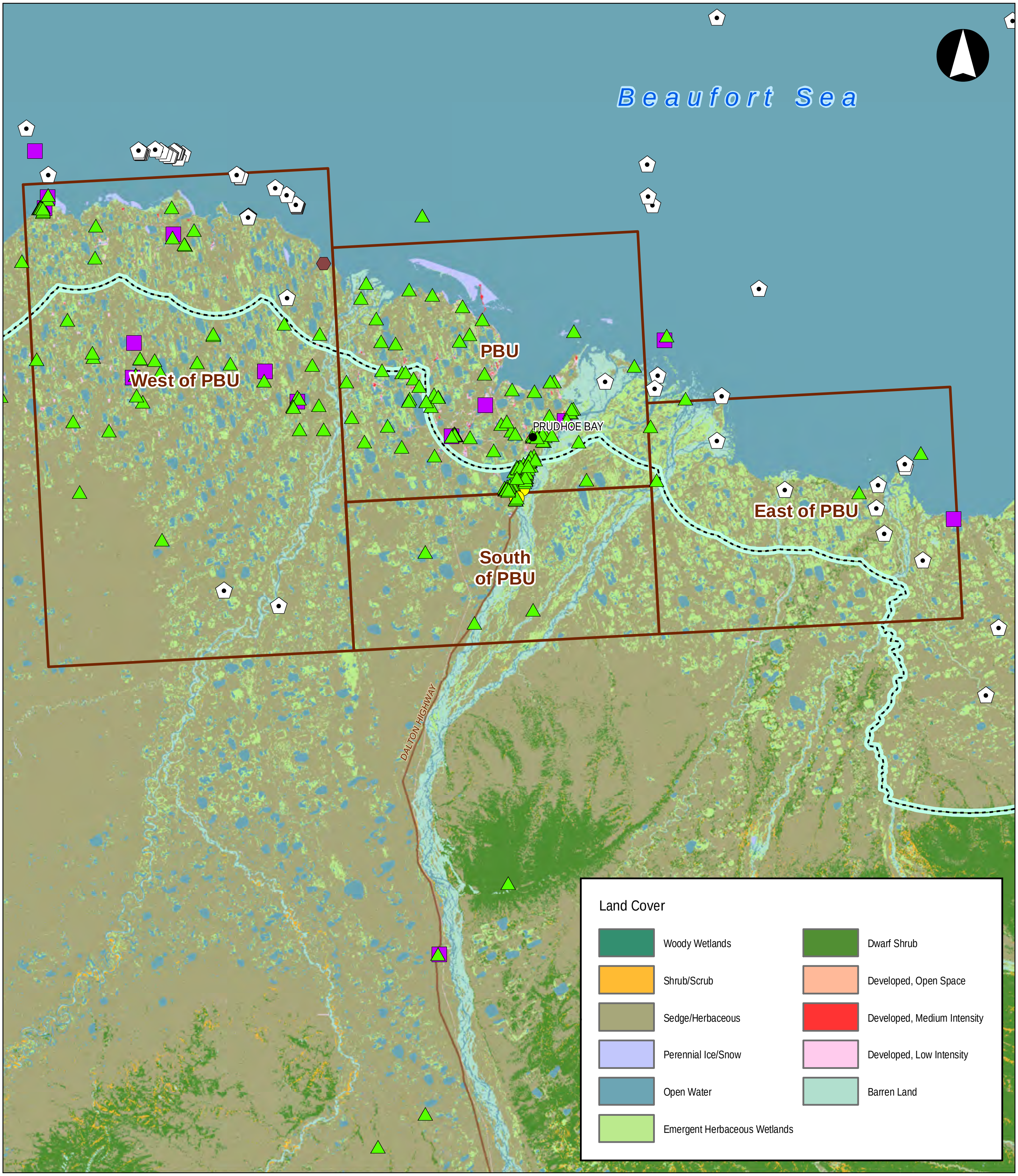
[e] Data is from SHPO and is dependent upon the number of surveys completed in the location—PBU has had a considerable number of surveys over the decades of oil and gas development.

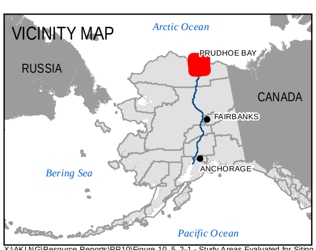
[f] ADEC Contaminated Sites Program

[g] A developed area with known contaminated sites, but they are isolated so that potential contamination migration does not appear to be an issue for siting of the GTP facility, and are being managed under a Resource Conservation and Recovery Act Corrective Action Order

[h] January 11, 2013, A federal district judge in Alaska set aside the USFWS final rule designating critical habitat for the polar bear under the ESA. See more at: https://www.morganlewis.com/pubs/federal-district-court-vacates-critical-habitat-designation-for-polar-bears#sthash.0We8bbWt.dpuf

The PBU area was identified as the proposed study area to examine for suitable alternative sites for the GTP. It is the study area in closest proximity to the predominant volume or percentage of existing gas sources, has infrastructure to support construction and operations, and would result in the least number and size of facilities required to move gas supply into a GTP as well as byproduct back to the operating units (pipelines to/from a GTP, compression required to move gas in both directions, haul roads from a dock on the North Slope, etc.). None of the other study areas were able to minimize these facilities, and therefore minimize a footprint to meet the objectives (see Table 10.5.2-1).





LEGEND

- Alaska Place Names
- Contaminated Sites - ADEC
- LUST Sites - ADEC
- Solid Waste Sites - ADEC
- FUDS Sites - USACE
- Recently Recorded Polar Bear Dens
- Study Areas for GTP Siting
- Proposed Polar Bear Critical Habitat
- Major Highways

0 3.75 7.5 15 Miles

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STUDY AREAS EVALUATED FOR SITING OF THE GTP

FIGURE 10.5.2-1

ALASKA LNG

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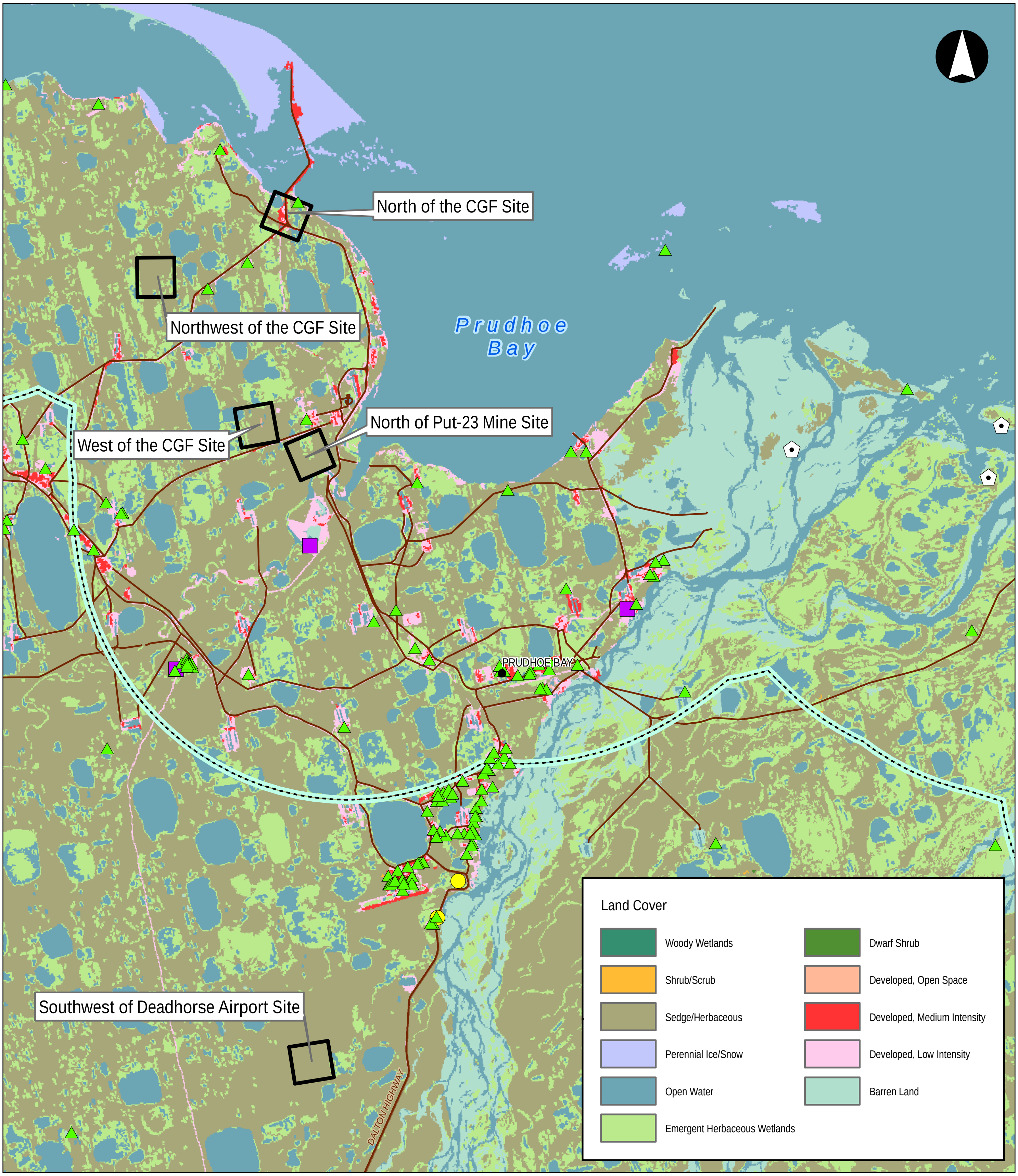
10.5.3 GTP Alternatives in the PBU Study Area

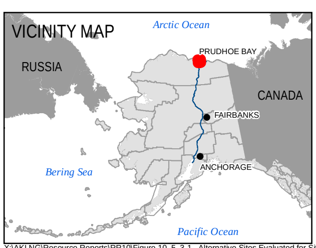
As noted in Section 10.5.2, the PBU area was identified as the proposed study area to identify a site for the GTP. Within this study area, the Project identified five potential alternative sites for siting of the GTP (see Figure 10.5.3-1):

- West of PBU CGF (Proposed Alternative GTP Site) – Located approximately 2,000 feet west of the existing PBU CGF;
- North of the Putuligayuk-23 (Put-23) mine – Located approximately 1.2 miles north of the Put-23 mine, between Put-23 and the PBU CGF;
- Southwest of Deadhorse Airport – Located approximately 3 miles southwest of Deadhorse Airport and 1 mile west of Dalton Highway;
- North of the PBU CGF – Located north of the PBU CGF/Central Compression Plant area on the Prudhoe Bay shoreline approximately 2,500 feet southeast of the West Dock staging pad; and
- Northwest of the PBU CGF – Located approximately 3.2 miles northwest of the PBU CGF/Central Compression Plant area off the existing K Pad access road.

The GTP site alternative located north of Put-23 mine is assumed to have an identical pad footprint to the Applicants' proposed alternative and a similar logistical execution plan consisting of using West Dock to offload the modules and transport them to the site, primarily using existing roads. Infrastructure differences among these alternatives is primarily the length of road upgrades, pipeline crossings, and new transfer line lengths. The GTP site alternative located southwest of the Deadhorse Airport and west of Dalton Highway has a similar logistical execution plan but the alternative pad size would be approximately 5 percent greater than the Applicants' proposed alternative pad size to accommodate additional compression needed for this alternative. The GTP site alternative located north of the PBU CGF/Central Compression Plant has a unique pad footprint that includes a newly built dock extending out into Prudhoe Bay. As a result, this alternative's modules would not need to be transported over existing roadways. The GTP site alternative located 3.2 miles northwest of the PBU CGF/Central Compression Plant area was developed to shorten the distance of module transportation to enhance schedule certainty.

The following subsections and Table 10.5.3-1 summarize the Project's analysis of each these alternative sites. Of note, alternative GTP site locations would also require shifting the starting point (MP 0) of the Mainline and ending point (MP ~62.5) of the PTTL.





LEGEND

- Alaska Place Names
- Contaminated Sites - ADEC
- LUST Sites - ADEC
- Solid Waste Sites - ADEC
- Recently Recorded Polar Bear Dens
- Major Roads
- Proposed Polar Bear Critical Habitat
- Alternative GTP Sites

0 1 2 4 Miles

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SCALE:	1:150,000		
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ALTERNATIVE SITES EVALUATED FOR SITING OF THE GTP

FIGURE 10.5.3-1

ALASKA LNG

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TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
Engineering/ Technical Considerations	Site Characteristics	Site Design Complexity (Relative Complexity)	Low	Low	Additional compression needed Location near Deadhorse Airport may impact design of the facility (building/stack height)	Moderately High Structural support of large modules (i.e., piles, footings, etc.) more complex due to increased potential for granular material subsidence in nearshore area	Low Additional pressure drop mitigation may be needed.
		Operational and Safety Criteria	Acceptable No nearby populated centers or infrastructure constraints for emergency egress Some safety concerns relative to polar bears greater potential for human/ interaction.	Acceptable No nearby populated centers or infrastructure constraints for emergency egress Some safety concerns relative to polar bears greater potential for human/ interaction.	Less Acceptable Could impact populated areas and Deadhorse Airport during a safety event Some safety concerns relative to polar bears greater potential for human/ interaction.	Least Acceptable Maintenance impacted by salt spray Operations impacted by higher wind speeds, additional wind-driven snow, and safety concerns relative to polar bears greater potential for human/ interaction Plant egress is constrained on shore side.	Acceptable No nearby populated centers or infrastructure constraints for emergency egress
		Land Use/Zoning	Locations with evidence of previous disturbance are present in close proximity to the site (e.g., pads, pilings)	Pipelines and elevated electrical utilities cross the site area. This location and surrounding area are located in the Prudhoe Bay vicinity near Put-	Site is located within 5 miles of the Deadhorse Airport Outside of the PBU (North Slope Borough development	Site is located on previously undeveloped coastal land, but is located within proximity to West Dock, roads, and other industrial development	Close to existing road network This location and surrounding area are located in the Prudhoe Bay vicinity. Land within the PBU is designated for

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
			This location and surrounding area are located in the Prudhoe Bay vicinity. Land within the PBU is designated for industrial development.	23 Mine. Land within the PBU is designated for industrial development.	permit would be required.)	This location and surrounding area are located in the Prudhoe Bay vicinity. Land within the PBU is designated for industrial development.	industrial development.
	Module Delivery	Approximate Route Length (Miles)	5	6.7	20	0	4
		Foreign Utility Line Crossings (Relative Complexity)	Minor Other existing and new crossings would require minor improvements to cross over.	Moderately Significant One large (~60-inch-diameter) elevated pipeline and one high-voltage power line would need to be crossed	Significant Numerous crossings would require significant upgrades	None	Minor Other existing and new crossings would require minor improvements to cross over.
		Route Transit Conflicts	Low Haul route issues on the spine road from West Dock	Moderate Haul route issues on the spine road from West Dock Good access to site during operations	Significant Modules must pass through highly developed and highly traveled areas to reach site from West Dock (crosses four roads and two pipelines) unless additional infrastructure is	None	Low Shortest haul road

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
					built to avoid these areas		
		West Dock Expansion	Would require upgrades to West Dock	Would require upgrades to West Dock (same as Applicants' proposed alternative)	Would require upgrades to West Dock (same as Applicants' proposed alternative)	No expansion of West Dock is required for this alternative. It would require a new dock.	Would require upgrades to West Dock (same as Applicants' proposed alternative)
	Granular material (million cubic yards)	West Dock Improvements	1.8	1.8	1.8	>1.0	1.8
		Pad and Access Road	7.1	7.0	7.3	7.5 (More granular material would also be required at the site for filling in low-lying areas. Granular subsidence would be more of an issue for this location.)	7.1
		New Roads	2.4	2.4	7.4 (More granular material is required due to the site's distance from Deadhorse.)	2.5	2.4
		Total	11.4	11.3	16.5	>11.0	11.4
	Infrastructure requirements (road and pipeline	Pipeline Connection to PBU Length (Miles)	0.9	1.3	12.5	4.5	3.2
		Foreign Pipeline Crossings (Number)	Uses existing crossings	2	2	3	1

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
	crossings by modules take considerable granular material to pad and protect the existing utility/road and allow module transport to site)	Roads	Uses existing roads	Uses existing roads	New road around Deadhorse	Uses existing roads	Uses existing roads
	Approximate length of the PTTL connecting the PTU and GTP from MP 40 of the PTTL west (miles)		19.03	17.91	17.12	20.36	21.80
	Approximate length of the Mainline connecting the Liquefaction Facility and GTP from MP 15 north (miles)		13.27	12.98	4.15	17.14	15.70
Environmental	Pad Footprint Inclusive of Flare Area (acres)		280	280	280 (+5 percent for booster compression)	280 (+10 percent for booster compression and module laydown)	280 (+5 percent for pressure drop mitigation if needed)
	Land Use[a] (Percent of Area) Does not include new/improved road, pipelines, or other infrastructure impacts	Wetland/Open Water (non-marine)[b]	25.5 (National Wetlands Inventory [NWI] maps—99)	13.7 (NWI maps—100)	1.5 (NWI maps—100)	47.7 (NWI maps—91)	19.3 (NWI maps—100)
		Developed (Low/Medium Intensity)	0.0	0.4	0.0	21.5	0.0
		Developed (Open Space)	1.2	0.4	0.0	0.6	0.0
		Vegetated (sedge, herbaceous)	73.3	85.5	98.5	30.3	80.7
	Seafloor Disturbance	Dredging Volume (Cubic Yards)	None anticipated	None anticipated	None anticipated	Yes, >4.5 million cubic yards, because of the need to dredge a channel to bring modules all the way to	None anticipated

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
						shoreline through shallower waters May require dredging of permafrost Yearly dredging maintenance is also higher for this alternative.	
	Water Supply		Requires development of a new reservoir	Requires development of a new reservoir	Requires development of a new reservoir	Requires development of a new reservoir	Requires development of a new reservoir
	Air Quality and Noise Note: all alternative sites would house workers on the pad itself for construction and operations.		The site is located in an industrial area. The GTP is expected to meet applicable ambient air and noise quality standards. Noise emissions resulting from pile driving and other in-water construction activities would have the potential to affect fish and marine mammals. The closest identified camp/hotel	The site is located in an industrial area and would be expected to meet applicable ambient air and noise quality standards. Noise emissions resulting from pile driving and other in-water construction activities would have the potential to affect fish and marine mammals. The closest identified camp/hotel location is 4.1 miles away.	The site would be expected to meet applicable ambient air and noise quality standards. Noise emissions resulting from pile driving and other in-water construction activities would have the potential to affect fish and marine mammals. The closest identified camp/hotel location is 3.7 miles away.	The site is located in an industrial area and would be expected to meet applicable ambient air and noise quality standards. Because pile driving and other in-water construction activities would be of longer duration, of greater magnitude, and cover a larger area, the potential risk that noise emissions resulting from these activities would impact fish and marine mammals is also increased. The closest identified camp/hotel location is 7.5 miles away.	The site is located in an industrial area. The GTP is expected to meet applicable ambient air and noise quality standards. Noise emissions resulting from pile driving and other in-water construction activities would have the potential to affect fish and marine mammals. The closest identified camp/hotel location is 5.9 miles away.

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered		**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
		location is 3.8 miles away.				
	Visual Impact	The site is located in the Prudhoe Bay area. The potential for visual impacts would be minor due to existing development in this designated area for oil and gas development.	The site is located in the Prudhoe Bay area. The potential for visual impacts would be minor due to existing development in this designated area for oil and gas development.	The site area would be just outside of developed area and extend the developed footprint. The potential for visual impacts would be greater than Proposed Site and Alternate 1.	The site is located along the coast and just outside of developed area. The potential for visual impacts would be greater than other sites.	The site is located in the Prudhoe Bay area. The potential for visual impacts would be minor due to existing development in this designated area for oil and gas development.
	Cultural Resources	Site is located to avoid historical landmark (original PBU discovery well)	No known cultural resource issues	No known cultural resource issues	No known cultural resource issues	No known cultural resource issues
	Soil Contamination	No known sites identified	No known sites identified but located adjacent to North Slope Borough Oxbow landfill	The site is located in undeveloped area and the probability of encountering contamination is low.	The site is located in an undeveloped area and probability of encountering contamination is low.	No known sites identified

TABLE 10.5.3-1

Comparison of the GTP Site Alternatives

Factors Considered			**Applicants' proposed alternative (west of the PBU CGF)**	**North of Put-23 Mine**	**Southwest of Deadhorse Airport**	**North of the PBU CGF (Onshore)**	**Northwest of the PBU CGF**
	Protected Species	Polar Bear	Located within potential feeding and denning areas	Located within potential feeding and denning areas, with a higher prevalence of denning habitat than the Applicants' proposed alternative	No relative difference from the Applicants' proposed alternative; located within potential feeding and denning areas	Located within potential feeding and denning areas, with a higher prevalence of habitat than the Applicants' proposed alternative	Farther from potential denning habitat than the Applicants' proposed alternative.
		Spectacled and Steller's Eiders	No relative difference from the other alternatives; located within potential nesting areas	No relative difference from the other alternatives; located within potential nesting areas	No relative difference from the other alternatives; located within potential nesting areas	No relative difference from the other alternatives; located within potential nesting areas	No relative difference from the other alternatives; located within potential nesting areas
		Bowhead Whale	No relative difference from the other alternatives; studies indicate that bowhead whales are generally not present in the Project area during July–September	No relative difference from the other alternatives; studies indicate that bowhead whales are generally not present in the Project area during July–September	No relative difference from the other alternatives; studies indicate that bowhead whales are generally not present in the Project area during July–September	No relative difference from the other alternatives; studies indicate that bowhead whales are generally not present in the Project area during July–September	No relative difference from the other alternatives; studies indicate that bowhead whales are generally not present in the Project area during July–September

[a] National Land Cover Database, percentages of are based on total land area, wetland percentage is based on very high-level aerial photointerpretation and not used for comparison.

[b] NWI data indicates the percentage of the geographic area that includes freshwater wetlands at 99 percent – Proposed Alternative; 100 percent – North of Put-23 mine; 100 percent – Southwest of Deadhorse Airport; 91 percent – North of the PBU CGF; 100 percent – Northwest of the PBU CGF

10.5.3.1 GTP Site Selection

As indicated in Table 10.5.3-1, none of the sites would have a markedly different impact on the environment, but differ in the extent of new infrastructure and improvements to existing infrastructure that would be required (resulting in additional environmental impacts). All of the site alternatives would require a new granular material source to support pad and road construction because existing sources are already allocated and a new water source to support construction and operations. All sites are predominantly wetlands (when reviewing National Wetlands Inventory [NWI] maps, not land use/land cover data) and would impact the same amount of wetlands.

Because of the similarities between the sites, the differences are primarily focused on the infrastructure required to facilitate use of the site and these are highlighted as follows.

10.5.3.1.1 Applicants' Proposed Alternative West of the PBU CGF

The Applicants' proposed site is centrally located within the PBU, adjacent to the PBU CGF (see also Section 1.3.2.2 for a full description of the Applicants' proposed alternative). This alternative would have the shortest length of pipelines to and from existing infrastructure (such as PBU CGF (< 1 mile) and nearby wells for by-product disposition) and there are no utilities or roads for these elevated pipelines to cross. Existing roads can be modified to facilitate transport of modules from West Dock and a granular material source can be developed near the existing infrastructure along the Put River. West Dock improvements involve building a new dock (Dock Head [DH] 4) at the Seawater Treatment Plant (STP), widening the West Dock Causeway, construction of a new module transfer site, and haul road widening to accommodate the large modules. Approximately 11.4 million cubic yards of granular material would be required for West Dock improvements, haul road widening, module staging area, and pad development.

10.5.3.1.2 GTP Site Alternative North of Put-23 Mine

The GTP site alternative located north of the Put-23 mine would require additional roadwork to facilitate the transport of large heavy modules from West Dock to the site. This would include crossing a 60-inch elevated pipeline and a high voltage electric line. To facilitate module transport, these utilities would need to be either shut down, removed from service, and alternate measures put in place to accommodate their use, or large granular material ramps would need to be developed to move modules over these utilities.

The PBTL from the PBU CGF would be approximately 0.4 mile longer compared to the Applicants' proposed alternative, and would require crossing two existing pipelines and one road, whereas the PBTL for the Applicants' proposed alternative would use existing crossings.

The GTP site alternative north of the Put-23 mine is located in an area identified by USFWS as having more-appropriate topographic and macrohabitat features for polar bear terrestrial denning habitat (USFWS, 2010). While impacts to polar bears could be mitigated, the potentially higher presence of denning sites might impact construction timing, routing, or operations. As a result, the GTP site alternative north of the Put-23 mine was eliminated from further consideration.

10.5.3.1.3 GTP Site Alternative Southwest of Deadhorse Airport

Access to GTP site alternative located approximately 5 miles southwest of the Deadhorse Airport and 1 mile west of the Dalton Highway would be via a 20-mile-long module haul route from West Dock, which is approximately 15 miles longer than the haul route for the Applicants' proposed alternative. Additional compression would be required to move gas between the site and the PBU CGF, which would increase the size of the pad.

This site also poses the greatest potential conflicts with ongoing PBU operations. Modules on the haul route would pass through highly developed and highly traveled areas to reach the site from West Dock unless additional infrastructure would be built to avoid these areas. Numerous utility lines, pipelines, and power lines would be crossed along the longer route to the site. Either the infrastructure would be temporarily put out of service or the modules would need to be transported over the utilities. With the site's proximity to the airport, PBU operations, and other Deadhorse activities, conflicts during transport of the GTP modules from West Dock (shutdowns) would likely occur.

The southwest of Deadhorse Airport alternative would require a larger footprint in an undeveloped nonindustrial area and, due to the need for increased compression, would also produce increased air emissions. The location of the site would result in increased impacts for the longer haul road, longer pipelines from the PBU CGF, and the conflicts that this location would impose during construction, and possibly operations, to the existing users and activities in the area. The southwest of Deadhorse Airport alternative was therefore dismissed from further evaluation in the analysis.

10.5.3.1.4 GTP Site Alternative North of the PBU CGF

The GTP site alternative located north of the PBU CGF area on the Prudhoe Bay shoreline, approximately 2,500 feet southeast of the West Dock staging pad, presents the greatest ease of site access during construction and operations. The site would require construction of a new dock for offloading of modules directly onto the pad. However, dredging of a channel to shore would be required, resulting in dredging of 4.5 million cubic yards at a minimum, and very large quantity amount of maintenance dredging between sealift seasons to maintain the channel due to sedimentation. The quantity of maintenance dredging that could be required is likely infeasible to complete in the summer season. The Mainline and PTTL would also have to be routed across the Putuligayuk River at its widest location, near the river mouth, to reach this coastal location. Furthermore, an onshore flare installation would be challenging as a result of the facility siting in proximity to existing roads and infrastructure.

A greater pad footprint than the Applicants' proposed alternative would be required because of the need to store modules as they are offloaded and the lower elevation of the site near the coastline. Additional compression would also be required to move the gas from the PBU CGF, and this would result in a larger pad footprint. More than 11 million cubic yards of granular material would be required.

Additionally, installation of piles would be deeper and not able to use the normal ad freeze piles installation method, the standard North Slope piling method of surrounding piles with a water/sand slurry that subsequently freezes to secure the piles. Because of the proximity to the ocean, the method would not work in the summer time because the active layer along the top of the permafrost would be unfrozen, and this method would need to be replaced with driving pilings deeper into the permafrost. The additional noise, adjacent to the ocean, would create more impacts to marine mammals and fisheries.

Although this site would avoid the complications of transporting modules across existing utilities and roads, avoiding conflicts with the PBU operators, the disadvantages of GTP site alternative located north of the PBU CGF compared to the Applicants' proposed alternative are that it would require a quantity of maintenance dredging that is likely infeasible to complete in the summer season, increase noise impacts to marine mammals and fisheries, and result in a larger pad footprint and impact.

The GTP site alternative north of the PBU CGF was determined not to be preferable due to the disadvantages described and was eliminated from further consideration.

10.5.3.1.5 GTP Site Alternative Northwest of the PBU CGF

The GTP site alternative located approximately 3.2 miles northwest of the PBU CGF/Central Compression Plant area off of the existing K Pad access road, provides a balance between the necessary module haul road length from West Dock, which is shorter than the proposed alternative, and the requirement for a longer Mainline, PTTL, PBTL, and GTP associated pipelines compared to the proposed alternative.

Although the GTP site alternative northwest of the PBU CGF is a potentially suitable site for the GTP, the Applicant did not investigate this alternative further. The pad size would be comparable, resulting in similar wetland impacts, while the road to/from the granular material site would be longer resulting in additional impacts.

10.5.4 GTP Layout Alternatives

10.5.4.1 Main GTP Pad

The layout of the GTP was evaluated for safety, accessibility (Emergency, Constructability and Maintenance), plot space requirement, schedule, and execution certainty considerations. At the proposed GTP site location, the facility is restricted to the south by an existing road and pipeline corridor. The facility is limited to the north and west by existing bodies of water, where efforts are taken to minimize the impact to those bodies of water. It was identified early on during plot plan development that, due to the prevailing wind, a northerly flare location from the GTP would be preferred.

Based on preliminary process safety dispersion modeling and estimates of blast overpressures, the Operations Center would be located on a separate granular pad. A site to the northwest of the GTP pad along the module haul road was selected for its proximity and access to GTP while being a safe distance away, and to minimize impacts to nearby bodies of water.

10.5.4.2 Access and Module Haul Roads

The proposed roads for the GTP were selected to (1) ensure sufficient access to and egress from the facility, (2) minimize granular material quantities and construction costs, and (3) avoid large lakes/rivers and major pipeline crossings to the extent practicable. The GTP would have two access roads, with a third service road connecting the GTP to the water reservoir and granular material mine. The main access road to the facility would double as the module haul and return roads, entering from the northwest corner of the GTP pad. To avoid and minimize impacts, this road uses existing roadways to the extent practicable.

An emergency egress road would be located on the southeast side of the GTP pad and connect to the existing PBU CGF facility. During later stages of design, tie-in locations between the third service road and existing PBU road network would be identified. The routes for the second and third access roads were selected based on safety concerns, avoiding existing traffic constraints, and decreasing travel distances to minimize vehicular emissions and fuel usage. Thus, alternative access road routes were not considered further.

10.5.4.3 Reservoir/Mine Site

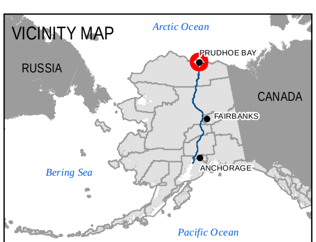
Construction of the GTP would require approximately 11.4 million cubic yards of granular material over the 8-year construction period. GTP operations would require clean and reliable sources of water for multiple purposes during construction and operations including gas treating, supply of potable water, fire water, construction of ice roads, hydrostatic testing, etc. A Project-specific mine site/water reservoir is planned to supply a portion of the granular material needed during construction and operational water requirements. This reservoir could also supply a portion of the water needed for construction. The water reservoir would need a capacity of approximately 250 million gallons. The proposed action is to source water from the Putuligayuk River as described in Resource Report No. 1.

The amount of granular material required (approximately 11.4 million cubic yards) for construction and the available sources of granular material found near the proposed site were evaluated. The existing Put-23 mine site is not expected to have sufficient capacity to support the entire volume needed for the GTP (about one-half of the volume is owned by the North Slope Borough for its use). It is possible that the Put-23 mine would be able to provide some of the early granular material needs for the Project. Other sites were not large enough in volume to be economically viable to transport over ice roads to the site. The development of a new reservoir site and a mine site for the GTP near the Putuligayuk River provides easy access to water and granular material of sufficient quantity and quality, which is normally found in abundance near rivers. The proposed location of the reservoir and mine site is also close to the GTP location, decreasing the emissions from granular material haul during construction. The reservoir and mine site will be sized to provide the volumes required during construction and operations. By using the granular material from the reservoir site, the area disturbed is reduced, and the mine site can be optimally planned and sized to support the later stages of construction once all the reservoir granular material has been used.

The Applicant evaluated several alternatives to source water and reservoir construction, including the following (see Figure 10.5.4-1):

- Use of water from the STP at West Dock — water used as enhanced oil recovery;
- Use of the Put-23 mine site as a reservoir (closing inactive cells and converting to a reservoir);
- Use of the Sagavanirktok River as a water source;
- Use of water from the North Slope Borough's water system; and
- Use of naturally occurring lakes, including supplemental deepening of naturally occurring shallow lakes.

VICINITY MAP



LEGEND

- Alternative Water Source
- Potential Deepened Lake Reservoir
- GTP Facility

0 0.5 1 2 Miles

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SCALE:	1:110,000		
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ALTERNATIVE WATER SOURCES EVALUATED FOR GTP OPERATIONS

FIGURE 10.5.4-1

ALASKA LNG

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The STP removes oxygen from the water and is not a desalination plant. Therefore, the output water is still saltwater, which is not a viable alternative as a potential source for the GTP. In addition, it is not considered by the Applicant to be a reliable source of water for the GTP because it is shut down for approximately four to six weeks each year due to high turbidity during the spring thaw. Thus, this alternative was not considered further.

The Put-23 mine is a heavily used granular material source with an undetermined depletion/expansion time. In the event certain locations of the Put-23 mine could be decommissioned and isolated to become a reservoir, there are concerns about relying on the ability of this site to supply water of suitable quality due to its proximity to existing granular material mining. Additionally, the close proximity to the Oxbow landfill could result in seepage that could compromise the purity of the water. Therefore, this alternative was not considered further.

Development of a new reservoir with a dedicated water source on the Sagavanirktok River was also considered as an alternative to the proposed reservoir (sourced from the Putuligayuk River) after it was determined that adequate surface water flow would potentially be available to support the GTP's annual water needs. Alternatives of transporting water to the GTP from the Sagavanirktok River include transportation by truck or construction of a new pipeline.

Trucking of the required volume of water would require multiple daily deliveries to the GTP, based on an estimated truck capacity of 300 barrels (i.e., 12,600 gallons), resulting in increased fuel use, traffic concerns, road deterioration, and related emissions during operations. Additionally, the reduced reliability of this supply option is unacceptable for such a critical resource. Water supplied via pipeline would be more reliable and less likely to be impacted by weather conditions (white-out conditions when trucks may not be able to operate, rig moves blocking truck routes, etc.); however, the Sagavanirktok River is significantly farther away from the GTP site than is the Putuligayuk River (approximately 4.75 miles farther). Construction of a pipeline from the Sagavanirktok River would result in greater environmental impacts due to the increased pipeline length needed, additional fuel to produce the electricity needed to power electric heat tracing during winter months to prevent the pipeline contents from freezing, additional granular material required for a maintenance road, and higher construction and operating costs. Therefore, this alternative was dismissed because of the additional impacts that would be incurred to pipe water from the Sagavanirktok River.

The alternative of supplying the GTP with water from the North Slope Borough's water treatment facility was considered, either through trucking of the water or via a pipeline connection. Similar to use of the Sagavanirktok River alternative described previously, the trucking demand or length of pipeline (approximately 9 miles) necessary to make the connection, and the associated potential environmental impacts and operating costs, make this alternative significantly less viable than use of the proposed reservoir. Further, the capacity of the North Slope Borough water sourcing systems is inadequate to supply the GTP with required water volumes and, therefore, would require a significant expansion and associated unfavorable impacts. The North Slope Borough water treatment plant, Service Area 10 (SA-10), currently only has limited water available:

- Potable water capacity for the facility is 250,000 gallons, with a production rate of 420,000 gallons per day; and
- Non-potable (utility/facility) water capacity is 125,000 gallons, with a production rate of 750,000 gallons per day.

It should be noted that both of these numbers are limited by the demands of other customers and the allotted volume of water the State of Alaska has provided. Thus, the alternative of using water from the North Slope Borough's water treatment facility was not considered further.

Five natural lakes that occur within 5 miles of the GTP were evaluated for their potential to provide the GTP's water requirements. They were all found to be approximately 5 feet or less in depth, and therefore highly likely to freeze to the bottom (note: approximate freeze depth is typically 8 feet). Additionally, none could meet the required water withdrawal demands of the Project, and/or all have significant prior water use commitments. Therefore, the use of these lakes was not found to be a viable alternative to the proposed reservoir.

Supplemental deepening of naturally occurring shallow lakes as an alternative for supply of the GTP's required water needs was also considered. Several lakes were identified that were potentially large enough to hold the required eight or more months of under-ice water supply if deepened, have no existing water reservations, and are within 5 miles of the proposed GTP. Disposal of the dredged material would be required to occur within onshore or Prudhoe Bay nearshore wetlands to economically deepen the lakes (transportation distance and number of miles of ice roads). However, the sites were considered to only be viable for storage of GTP water (not as a continuous water source), due to the lack of connectivity to a water source that would provide sufficient natural recharge. Similar to the proposed reservoir, they would still require seasonal withdrawal of water from either the Putuligayuk or Sagavanirktok rivers and construction of a new pipeline or trucking of the water to refill them. In addition, the material dredged from the lakes would most likely not be suitable for construction uses, necessitating the need to have a separate granular material mine. Therefore, the Applicant did not identify any environmental advantage of disturbing the existing natural systems over construction of a new reservoir in close proximity to the GTP, and the alternative of deepening of natural lakes was not considered further.

10.5.5 GTP Technology Alternatives

10.5.5.1 GTP Facility Energy Needs

GTP energy needs can be broken into three basic design categories.

- Gas compression – Approximately 505,000 International Standards Organization (ISO) horsepower would be required to drive GTP treated gas and byproduct gas compressors;
- Process heat – approximately 2,700 million British Thermal Units per hour heat duty is needed to recycle/regenerate the acid gas removal (amine); and
- Electric power – approximately 230 ISO megawatts of electric power would be required to support operation of GTP beyond gas compression and process heat needs.

These approximate values represent the proposed basis of design.

10.5.5.2 Energy Supply Alternatives and Environmental Impacts

10.5.5.2.1 Compression

The GTP would generate two gas streams as a result of gas treatment: an intermediate pressure LNG-quality treated gas stream, and a low pressure byproduct gas stream that contains gasses removed by treatment (primarily CO_2). The treated gas must be compressed so it can be sent to the Mainline, and byproduct gas must be compressed for delivery to the PBU. For both of these gas streams, power is needed for the compressors. The Applicant has considered whether to drive the treated gas and byproduct compressors with natural gas turbines or electric motors (electric GTP [eGTP]) (see Table 10.5.5-1).

TABLE 10.5.5-1

Comparison of GTP Gas Compression Alternatives

Evaluation Criteria		Alternatives (Applicants' proposed alternative is natural gas turbines)	
		Mechanical Drive Natural Gas Turbine	**Mechanical Drive Electric Motor (eGTP)**
Engineering/Technical Considerations	Process	A natural gas turbine is coupled directly and drives the treated gas or byproduct compressor.	An electric motor is coupled directly and drives the treated gas or byproduct compressor; electric power is generated by natural gas turbines in another area of the facility.
	Design	Less complex facility electric power/distribution system than eGTP	More complex facility electric power generation/distribution system; for combined cycle, significantly complex water treating system and increased water consumption
	Construction	Easier construction complexity; reduced electric power system	Most complex to construct Increased number of drivers Gas turbine drives electric generator; electric motors drive compressors
	Operability	Easy to operate	Hardest to operate because of variable frequency drive and transformer for motors
Environmental	Footprint	Smallest overall footprint	Highest overall Smaller process module footprint negated by higher power generation footprint
	Water	Minimum consumptive water use and wastewater generation	Highest consumption water use and wastewater generation if power generation is combined cycle
	GHG Emissions[a,b,c]	Lower	Higher
	Other Air Emissions (NOx, etc.)[a,b,c]	Lower	Higher
	Noise	Would meet noise standards	Would meet noise standards
	Visual Aesthetics[d]	Higher	Lower

TABLE 10.5.5-1

Comparison of GTP Gas Compression Alternatives

Evaluation Criteria	Alternatives (Applicants' proposed alternative is natural gas turbines)	
	Mechanical Drive Natural Gas Turbine	**Mechanical Drive Electric Motor (eGTP)**
Cost	Lower	Higher

[a] All alternatives are bounded by BACT for GHG and other emissions under the Clean Air Act.

[b] Assumes combines cycle power generation is not practicable due to consumptive water use and/or other impacts. See Table 10.5.5.-3 for description of power generation options.

[c] Simple cycle power generation is the baseline for the emission comparison and visual aesthetics.

[d] Based on the visibility of turbine exhaust plumes due to condensed water vapor.

Although eGTP results in higher availability on a standalone basis, concerns exist as to whether the increased availability could be leveraged on an integrated Project basis (misalignment of the planned maintenance with the Mainline and the LNG). In addition, eGTP is expected to result in higher overall facility air emissions due to the addition of fired heaters needed for process heat (see Section 10.5.5.2.2.) and larger power generation requirements. The more-significant emissions reductions typically associated with use of combined cycle power generation are not practicable to attain, because the amount of fresh water necessary to support the alternative would significantly increase the water demand of the GTP, with cascading effects on reservoir size, withdrawal from the Putuligayuk River, and associated environmental impacts. Even if practicable for consumptive water use, combined cycle power generation would come at a cost of increased footprint, wastewater generation, and visual aesthetics (see Table 10.5.5-3 for details). Without practicability of combined cycle power to supply motor electric needs, the eGTP option loses most of its benefits while downsides remain largely unchanged.

For gas compression, the Project has eliminated eGTP as a potential proposed alternative. Mechanical drive natural gas turbines remain as proposed alternatives.

10.5.5.2.2 Process Heat

The GTP would require a process heating system to provide a means for regenerating the acid gas removal medium (amine). The Applicant has considered whether to provide the process heat using WHRUs where technically feasible to recover heat that would otherwise be lost from the natural gas turbine exhaust or standalone natural gas fired heaters. Alone, the waste heat from the natural gas turbine exhaust is not sufficient to meet the heat duty requirements of the process. Supplemental natural gas firing would be required to further increase the temperature of natural gas turbine exhaust to extract enough heat in the WHRUs to satisfy process needs. Table 10.5.5-2 compares WHRU with supplemental natural gas firing to standalone natural gas fired heaters.

TABLE 10.5.5-2

Comparison of GTP Process Heat Alternatives

Evaluation Criteria		**Alternatives**	
		Waste Heat Recovery Units with Supplemental Firing (Applicants' Proposed Alternative)	**Fired Heaters**
Engineering/Technical Considerations	Process	Process heat requirements are met, where technically feasible, by WHRUs installed in exhausts of natural gas turbines; supplemental natural gas firing augments WHRUs as necessary	Process heat requirements are met by dedicated natural gas-fired heaters, no heat recovery from natural gas turbines
	Design	Likely no differential	Likely no differential
	Construction	Likely no differential	Likely no differential
	Operability	Likely no differential	Likely no differential
Environmental	Footprint	Lower	Higher
	Water	Likely no differential	Likely no differential
	GHG Emissions[a]	Lower – less natural gas fuel consumption	Higher – more fuel consumption
	Other Air Emissions (NOx, etc.)[a]	Lower – supplemental firing emissions likely much less than fired heaters	Higher
	Noise	Lower	Potentially higher, depending on design of heater employed
	Visual Aesthetics	No differential	No differential
Cost		No differential	No differential

[a] All alternatives are bounded by BACT for GHG and other emissions under the Clean Air Act.

The Applicant has identified WHRUs where technically feasible with supplemental firing as the proposed alternative for GTP process heat. WHRUs result in reduced emissions and footprint, and are essentially neutral for other engineering, environmental, and cost evaluation criteria.

10.5.5.2.3 Electric Power

The Applicant investigated the availability and capacity of the PBU and determined that there is not sufficient capacity to provide for the entire Project needs at the GTP. Utilizing the PBU through use of an overhead powerline as emergency power is still being evaluated.

Alternatives for electric power supply based on renewable energy sources were not developed. Renewable sources of energy such as solar are not practical due to the absence of sunlight in the winter and wind power would require hundreds of additional acres of impacted wetlands due to the large number of wind turbines required. The lack of alternatives is based on the Project's need for a consistent supply of power that could not be met by any potential renewable energy option. Section 10.2.1 provides additional details regarding limitations of renewable energy options.

The alternatives in Table 10.5.5-3 are based on the need for a consistent supply of power that is generated on site. Natural gas is the fuel common to all of the options, given its local availability in necessary quantities. In addition, natural gas inherently has fewer environmental impacts compared to other fossil fuels, such as coal or oil.

TABLE 10.5.5-3

Comparison of GTP Electric Power Alternatives

Evaluation Criteria		**Alternatives (Applicants' proposed alternative is the simple cycle alternative)**	
		Simple Cycle Natural Gas Turbines	**Combined Cycle Natural Gas Turbines**
Engineering/Technical Considerations	Process	Single Power Cycle: natural gas turbine drives electrical power generator	Dual Power Cycle: Uses exhaust gas from natural gas turbine to generate steam; steam is used to drive a separate steam turbine; both natural gas and steam turbines drive electric power generator
	Design	Less complex	Complex – requires addition of steam turbine, as well as steam generator, water treatment and steam condensing equipment; Arctic freeze protection a major concern
	Construction	Simplest to construct	Complex to construct
	Operability	Easiest to operate	Hardest to operate
Environmental	Footprint	Smallest	Highest
	Water	Minimal consumptive water use and wastewater generation	Consumptive water use for steam generator make-up would significantly increase GTP water demand; treatment of saline water from groundwater or Beaufort Sea impractical
	GHG Emissions[a]	Higher	Lower
	Other Air Emissions (NOx, etc.)[a]	Higher	Lower
	Noise	Low	Low
	Visual Aesthetics[b]	Low	High
Cost		Lower	Highest

[a] All alternatives are bounded by BACT for GHG and other emissions under the Clean Air Act.

[b] Based on visibility of turbine exhaust plume due to condensed water vapor

Simple cycle natural gas turbine is the Applicants' proposed alternative for power generation. While it may result in higher air emissions, it offers fewer impacts related to water, wastewater, visual aesthetics, and footprint. The make-up water requirements to the steam cycle would increase the GTP water demand about 50 percent. This would significantly increase the water withdrawal from the Putuligayuk River and increase the size of the reservoir being developed for the GTP. Simple cycle power generation also offers a number of practical benefits related to design, construction operability, and cost.

As noted in the eGTP gas compression discussion, the Applicant has eliminated combined cycle as a potential proposed alternative due to the amount of fresh water needed to support that alternative.

10.5.6 Module Delivery Alternatives

The proposed design basis is to use modules to facilitate the construction of the GTP based on a four-year, open-water season sealift delivery schedule. These modules would have an approximate 90-foot-wide, 300-foot-long footprint, and would weigh about 9,000 short tons.

The largest modules would need to be shipped by sealift because the size and weight of the modules exceed the capacity of either truck or rail transportation (see Sections 10.5.7.2 and 10.5.7.3). The Applicant is examining the feasibility of using smaller modules than the maximum sizes examined and discussed here and the impacts of that to construction schedule and in-service date.

10.5.6.1 Onsite Fabrication

As an alternative to using modules, it was considered whether onsite fabrication of the GTP components was a viable alternative. In considering this alternative, the Applicant examined what would be required to deliver the components necessary for onsite fabrication, as well as construction of the GTP once onsite fabrication was completed.

Because there are many options on the size (dimensions and tonnage) of components that are shipped to the GTP site for fabrication, components that are heavier than the maximum load allowed for the Dalton Highway (100 tons) (even if rail is used to Fairbanks, the module or component would still need to be transported by road to the site) would still need to come in by barge. This would look similar in impacts and construction considerations to the larger modules; however, there would be more deliveries per sealift, extending the number of sealifts and increasing the barge traffic to West Dock.

Onsite fabrication of the GTP would require a substantially larger footprint (two to three times the proposed size) to provide a place to store the components as they are delivered; space to assemble the components before moving them onto the operations portions of the pad for assembly and tie-in; and all of the additional equipment necessary on site to move, hold, and assemble the material as it is built into the modules that would have been transported by sea to West Dock. The additional equipment to move and assemble the material for onsite fabrication would also more than double the air emissions during the construction period. Onsite fabrication would also require that structures be built to enclose the component assembly areas to allow work to continue through the winter in Arctic conditions. Otherwise, construction would only occur for three or four months per year, greatly prolonging the construction impacts of the Project. Even with weather enclosures, fabrication on site would increase the schedule by two to three years to fabricate all the components to feed into GTP construction described in Resource Report No. 1.

Housing the additional workers would increase the footprint of the camp size by an order of magnitude for the thousands of workers required to assemble all of the parts that could otherwise be transported as an assembled unit. Combined with the logistical considerations to feed, care for, and supply resources for this larger construction effort, it becomes logistically impracticable to accomplish onsite fabrication.

Completely fabricating on site would substantially increase the cost of the GTP (by approximately double). To date, no significant oil and natural gas facilities have been fabricated on the North Slope due to Arctic conditions (see prior enclosure discussion) and cost. Additional information regarding the delivery of the material necessary for onsite fabrication is discussed in the following sections.

10.5.6.2 Truck Transportation

Truck transportation is the most common method to transport freight to the North Slope, with travel times from 4 to 10 days depending on site of origin, size, and weight of the module, weather, and other demands for road uses that may be present during transport. Special permits from ADOT&PF are required to transport modules larger than 22 feet wide by 15 feet, 6 inches high, by 80 feet long, and exceeding 100 tons gross weight (1/200 of the size and 1/100 of the weight of the proposed modules). The heaviest load that has ever been carried on Alaska roads from Anchorage to Prudhoe Bay to date was 20 feet wide by 14 feet, 6 inches high, by 76 feet long, with 110 tons gross weight. Several of the road route segments to Prudhoe Bay have limitations or restrictions (even if the limitations were addressed with infrastructure improvements or enhancements, the size and weight of the modules would still be limited to less than 200 tons), including:

- Nikiski to Anchorage: Weight limitation at the Canyon Creek Bridge;
- Anchorage to Fairbanks: Height restriction of 15 feet, 6 inches, at Nenana River Bridge in Rex and Tanana River Bridge in Nenana; and
- Fairbanks to North Slope: Safety standard considerations, in particular at Atigun Pass, with slopes up to 18 percent. In addition, there is a 110-ton weight restriction for multiple bridges along this segment.

All paved and unpaved roads maintained by ADOT&PF allow 100 percent legal axle load with overloads allowed upon application and receipt of written authorization from the Division of Measurement and Standards and Commercial Vehicle Enforcement. Between April 1 and June 1, however, load restrictions may apply due to weather conditions, varying between 50 and 100 percent of legal axle load.

Thus, transportation of more than 58,000 tons of equipment and approximately 250,000 tons of material by road is not practical, especially due to the limitations associated with the Dalton Highway, the only road connection to Prudhoe Bay (i.e., two-lane, 360-mile-long, mostly unpaved highway). Bridge weight restrictions of approximately 100 tons and road closures due to ice, snow, and breakup all increase safety, schedule, cost, and execution risks. Transporting that much material along the Dalton Highway would also increase the time required to build the GTP, result in a larger footprint to store all the material on the North Slope, and result in conflicts with tourism uses in the same road network over the period of construction. Even if the Dalton Highway were doubled in size, the maximum module size would never be able to reach that considered to be moved by barge. Therefore, although road improvements could reduce the number of trips by truck, they would not significantly offset the major impact of doubling (or greater) the footprint of the Dalton highway for 500 miles.

Therefore, this alternative was eliminated from further consideration, other than for transportation of materials (food, expendables used during construction, and smaller construction materials that can be shipped in bulk) and some small skids and modules.

10.5.6.3 Rail Transportation

Smaller modules fabricated in Alaska could be shipped via rail to Fairbanks using the Alaska Railroad Corporation infrastructure, which has undergone improvements over the last 10 years. The maximum railcar loading for the Alaska Railroad cannot exceed the gross weight of the railcar and cargo of 263,000 pounds. However, the Alaska Railroad system does not extend to Prudhoe Bay, so all-rail shipments would then have to be transported via highway after reaching Fairbanks. As discussed, the constraints along the Dalton Highway would be applied here, including breaking modules into smaller sizes to be able to be transported along the highway; the additional time to move from rail to the road would require a storage and handling yard in Fairbanks; and overall the number of trips would not be reduced. Therefore, this alternative was eliminated from further consideration.

10.5.6.4 Barge Ballast Bridge

The Applicant evaluated the alternative of using a barge ballast bridge option for the delivery of modules to minimize or eliminate the need for dredging. A barge bridge is typically built by bringing in the smallest barges with the smallest modules first (lowest water depth requirement for navigation) and gradually increasing barge/module size as the barge bridge extends into deeper water. The use of a barge ballast bridge was determined not to be feasible for the proposed alternative of offloading modules from DH 4 for the following reasons:

- A barge bridge would need to extend for approximately 1,500 feet to deep enough water to accommodate module offloading. This would require approximately 5 or more empty barges, for each of the five planned berths, for a total of approximately 25 barges; and
- The uneven water depth between DH 4 and the 12-foot water depth contour would require screeding to create an even bottom profile for barges to be safely ballasted to the seabed.

10.5.7 North Slope Dock Alternatives

While there are numerous dock structures in and around Prudhoe Bay, there is only one major dock close enough to the GTP site to support construction of the facility, which is West Dock. This dock was built when the original PBU facilities were developed and has been used over the years in maintaining and replacing the major equipment at the PBU.

Other module offloading docks considered by the Applicant is listed in Table 10.5.7-1 and depicted in Figure 10.5.7-1. Based on the comparison shown for the existing docks, there are no practicable or logistically feasible alternatives to the use of West Dock. All of the other docks identified would require similar or greater environmental impacts (dredging, building new roads and/or modifying existing roads, air emissions of module transportation). In addition, West Dock is the closest port facility to the proposed GTP site. This allows modules to be offloaded and transported to the site within the open-water season window with a high probability of success. The other locations are much farther (up to 60 miles) and with the slow movement of the module transporters (<0.5 mile per hour), would increase the risk that modules could be moved to the site in the open-season window. The analysis indicates that West Dock would be the best solution to moving the modules onshore and is the Applicants' proposed alternative.

ALTERNATIVE OFFLOADING DOCK SITES EVALUATED FOR THE GTP

FIGURE 10.5.7-1

ALASKA LNG

LEGEND

- Offloading Dock Sites
- Project Facility
- Existing Facility
- Alaska LNG Rev C2 Route
- Point Thomson Transmission Line
- Major Highways

0 2.5 5 10 Miles

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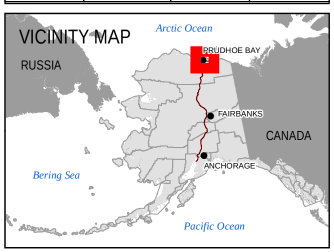
VICINITY MAP



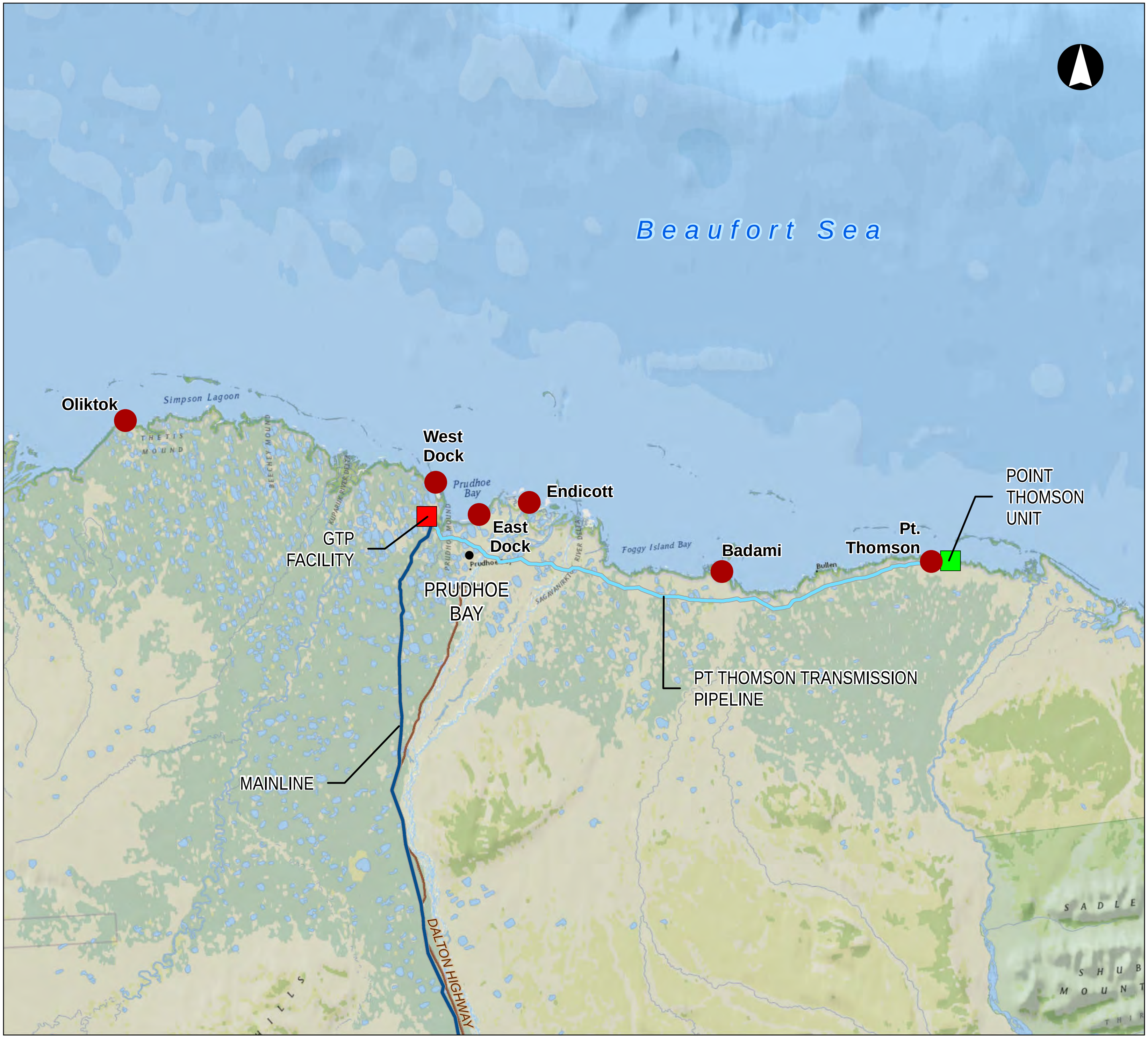


TABLE 10.5.7-1

Alternative Offloading Docks and Identified Constraints

Criteria		**West Dock (Applicant proposed alternative)**	**Badami Dock**	**East Dock**	**Endicott Main Production Island and Satellite Drilling Island**	**Oliktok Dock**	**Point Thomson Dock**
Engineering/ Technical Considerations	Approximated Distance from GTP Area (miles)[a]	Basis for comparison (<7 miles)	39	7	16	33	53
	Existing Road Infrastructure	Yes	No	Yes	Yes	Yes (Extensive Kuparuk infrastructure obstructions along route)	No
	Existing Dock	Yes	Yes	No (Currently just an 800-foot-long granular material feature)	Yes	Yes	Yes
	Existing Berths	Yes (Currently two berths)	Yes (Currently only one berth)	No	Yes (Currently there are two berths at the Endicott Island and one at the Satellite Drilling Island.)	Yes (Currently only one berth)	Yes (Currently only one berth)
Environmental	Onshore disturbance	Approximately 5 miles of road upgrades and new roads	Approximately 39 miles of new roadway would need to be constructed to connect to the PBU.	Existing roads would require approximately 15 miles of road upgrades.	Four bridges would need to be replaced along the inland route. Approximately 16 miles of road upgrades.	Three bridges would need to be replaced along the inland route. Approximately 33 miles of road upgrades.	Approximately 60 miles of new roadway would need to be constructed to connect to the PBU.
	Seafloor Disturbance	None	Dredging required due to shallow water	Dredging due to shallow water (approximately 2 feet deep at dock)	Potential dredging requirement would need to be assessed	Dredging required due to shallow water	Dredging due to shallow water (approximately 7 feet deep at dock)

[a] Straight-line distance

10.5.7.1 West Dock

Construction of the GTP would require a dock to bring in the modules; approximately 65 modules during the pre-sealift and 51 modules during the sealift. The heaviest modules, including transportation steel, weigh approximately 9,400 tons plus the weight of the SPMTs that would carry them overland.

Table 10.5.7-2 summarizes the scope of each sealift, and Table 10.5.7-3 summarizes the scope of each pre-sealift year.

TABLE 10.5.7-2

Sealift Execution Summary

Sealift Year	**3 Train, Four Sealift Basis (Excludes NEG Year Logistics)**	**# of Barges**	**# of Modules**	**Neat Weight (ST)**	**Execution Weight = Neat Weight + 20% + 7% (ST)**
Sealift 1 (2023)	Utilities + Main Pipe Racks + 1 of 3 Power Generation Modules + AGRU Absorber Vessels + Flare Stacks + Partial Propane System	12	17	35,400	45,500
Sealift 2 (2024)	First Train + 2nd Power Generation + Propane Compression + Flare KO Drum Module + Fuel Gas Heaters + Heat Medium Utilities Heaters **Gas Produced: 33% Production (2025)**	12	15	62,400	80,100
Sealift 3 (2025)	Second Train + 3rd Power Generation Module **Gas Produced: 66% Production (2026)**	10	10	50,500	64,800
Sealift 4 (2026)	Third Train Gas Produced: 100% Production (2027)	9	9	44,200	56,800
Total		**43**	**51**	**192,500**	**247,200**

TABLE 10.5.7-3

Pre-Sealift Execution Summary

Pre-Sealift Year	**Prefabricated Items delivered in advance of Main Sealift**	**# of Barges**	**# of Modules / Assemblies**	**Neat Weight**	**Execution Weight = Neat Weight + 20% + 7% (ST)**
NEG 4 Trucked Materials (2019)	Pioneer Camp Piles	N/A	Misc. Piles	1,200	1,500
NEG 3 Tucked Materials (2020)	Integrated Construction and Operations Center (ICOC) and Associated Piles (Weight Excludes Truckable ICOC)	N/A	Misc. Piles	10,500	13,500

TABLE 10.5.7-3

Pre-Sealift Execution Summary

Pre-Sealift Year	Prefabricated Items delivered in advance of Main Sealift	# of Barges	# of Modules / Assemblies	Neat Weight	Execution Weight = Neat Weight + 20% + 7% (ST)
NEG 2 Barged Materials (2021)	VSM Piles, PBTL Line Pipe, PUT River and Reservoir Modules, Camp Utilities, Communication Building, HC Holding Tank, GTP Transformers	9	8 modules/ Assemblies + Line Pipe + Pipe	33,000	42,400
NEG 1 Barged Materials (2022)	Balance of Field Erected Items, incl. WHRU Packages Turbine Stacks and Air Intakes, Flare Rack and Blowcases, Misc. Utilities and Tanks, Cable Racks, Transformers and and Tanks, Cable Racks, Transformers	9	57 Modules / Assemblies / Transformers + Misc. Field Erected Pieces	22,200	28,500
Total		18	65	66,900	85,900

Currently, West Dock has two existing DHs: DH 2, which serves heavy loads; and DH 3, which does not. The STP at the end of the West Dock Causeway does not have a dock. The presence of ongoing production operations near DH 3 may also constrain its use for module transfers. The Project evaluated DH 2 and DH 3 as alternatives to a new dock (DH 4) at STP. Two different DH4 configurations were evaluated. A comparison of the alternatives is provided in Table 10.5.7-4 and the facilities are depicted in Figure 10.5.7-2.

TABLE 10.5.7-4

West Dock Facility Alternatives and Identified Constraints

Criteria		DH 2	DH 3	DH 4 – STP Option	DH4 – No Channel Option (Applicants' proposed alternative)
Engineering/Technical Considerations	Existing Dock	Yes	Yes	No	No
	Required Dock Expansion	Construct five or more new berths for offloading	Construct five or more new berths for offloading	Construct five or more new berths for offloading	Construct five or more new berths for offloading
	Required Causeway Bridge improvements or additions	None	One new bridge to cross a 650-foot breach, or grounded barges to cover the breach gap in lieu of a new bridge	One new bridge to cross a 650-foot breach, or grounded barges to cover the breach gaps in lieu of a new bridge	One new bridge to cross a 650-foot breach, or grounded barges to cover the breach gaps in lieu of a new bridge.
	Required Causeway Widening	Widen existing causeway from 40 feet to 125 feet Shortest distance of required widening	Widen existing causeway from 40 feet to 125 feet from shore to DH 2 Widen existing causeway from	Widen existing causeway from 40 feet to 125 feet from shore to DH 2 Widen existing causeway from 40 feet to 125 feet from	Widen existing causeway from 40 feet to 125 feet from shore to DH2 Widen existing causeway from 40 feet to 125 feet from

TABLE 10.5.7-4

West Dock Facility Alternatives and Identified Constraints

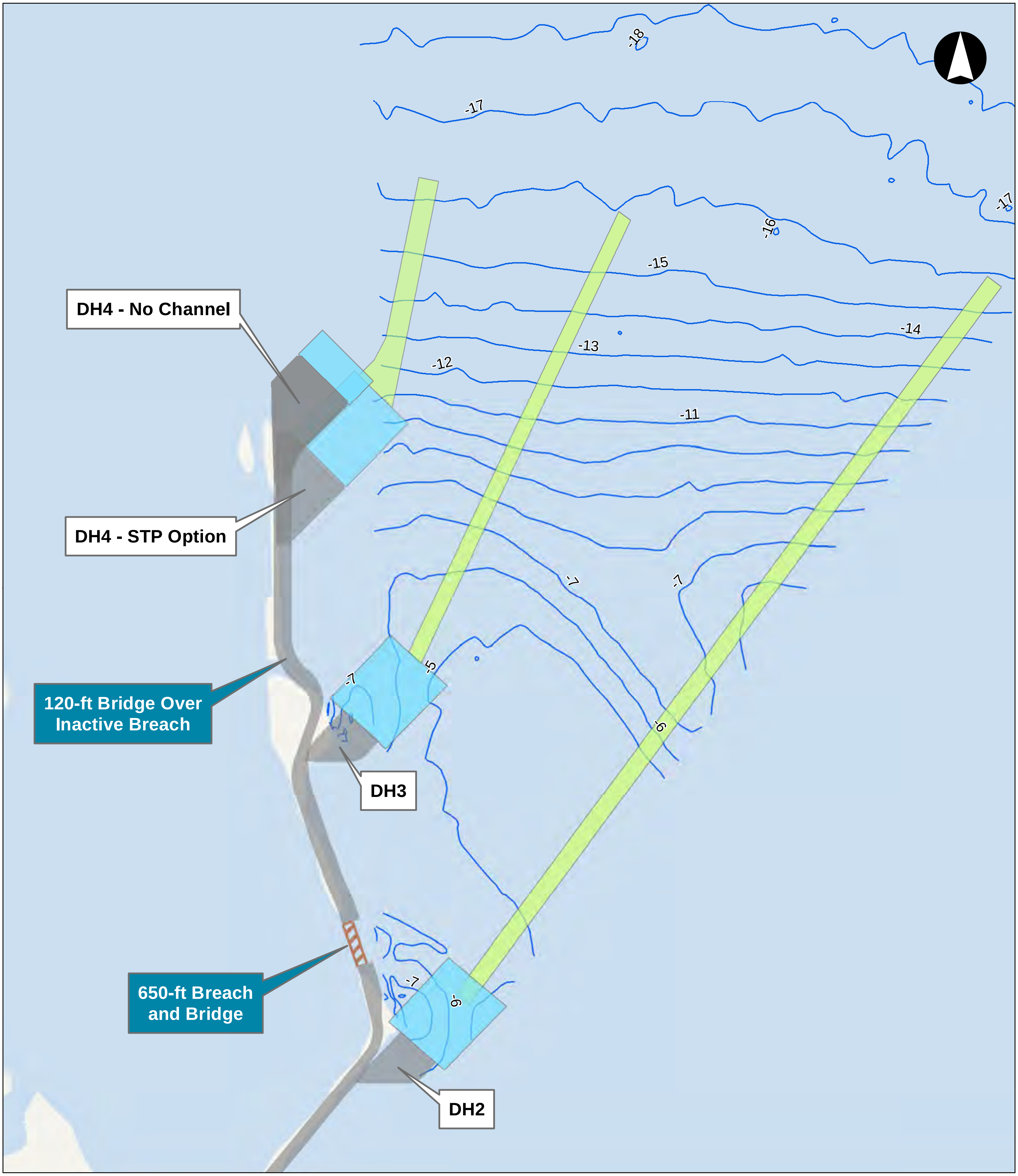
Criteria		**DH 2**	**DH 3**	**DH 4 – STP Option**	**DH4 – No Channel Option (Applicants' proposed alternative)**
			40 feet to 125 feet between DH 2 to DH 3	between DH 2 and DH 3 Widen existing causeway with a 125-foot-wide adjacent between DH 3 and STP due to the higher elevation of the existing causeway at this location	between DH2 and DH3 Widen existing causeway with a 125-foot-wide adjacent strip between DH3 and STP due to the higher elevation of the existing causeway at this location
	Potential for Interference with Existing Production Facility	Minimal (potential interference with traffic between the shore and operating well at DH 3 and/or STP)	Yes (operating well at DH 3, plus potential interference with traffic between the shore and operating well at DH 3 and/or STP)	Yes (operating well at DH 3 plus potential interference with traffic between the shore and operating well at DH 3 and/or STP)	Yes (operating well at DH3 plus potential interference with traffic between the shore and operating well at DH3 and/or STP)
Environmental	Seafloor Disturbance	Longest length of channel dredging (approximately 14,000 feet). Dredging also required for maneuvering basin.	Shorter length of required channel dredging than DH 2 (approximately 8,600 feet). Dredging also required for maneuvering basin.	Shortest length of required channel dredging (approximately 3,600 feet). Dredging also required for maneuvering basin.	No dredge channel
	Emissions	Trade-off between longer barge transport distance and shorter transport distance by SPMT to the GTP. Anticipated that dredging operations would have greatest impact on emissions.	Trade-off between barge transport distance and transport distance by SPMT to the GTP. Anticipated that dredging operations would have greatest impact on emissions.	Trade-off between shorter barge transport distance and longer transport distance by SPMT to the GTP. Anticipated that dredging operations would have greatest impact on emissions.	Likely to be the lowest since dredging operations eliminated

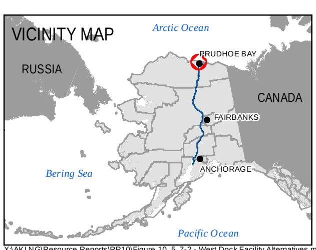
Although both DH4 options require a longer travel distance and installation of a new parallel causeway segment, the No-Dredge Channel option eliminates a significant amount of offshore disturbance. When compared to channel lengths of 8,600 feet to DH 3 and 14,000 feet to DH 2 and dredge volumes of 3.3 and 4.5 million cubic yards for DH 3 and DH 2 respectively, the advantages of this DH4 options are significant. Additionally, there is a significant risk of sedimentation infill at DH 3 and DH 2, which would increase the risk of delaying the sealift schedule should necessary summer dredging be performed right before the sealift. Any additional work would impact the number of modules that could be successfully offloaded and transported to the pad during the ice-free window.

Due to the need for a longer dredge channel, initial and maintenance dredge volumes, and risk of infill compromising the ability to offload within the available window, use of DH 3 and DH 2 were not considered to be the Applicants' proposed alternative.

Of the two DH4 alternatives, the No Dredge Channel DH4 option is the Project's proposed alternative because the offload location is in deeper water.

Although the implementation of the 2016 bathymetric survey data provides a good level of confidence with respect to the location of DH4 as currently proposed, refinements to the design and location may be required as a result of seafloor changes or similar issues.





LEGEND

- Bathymetry Contours
- Temporary Barge Bridge
- GTP Improvement Footprint
- Proposed Berthing Basin
- Proposed Alternative Dredge Channel Alignment

0 0.1 0.2 0.4 Miles

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WEST DOCK FACILITY ALTERNATIVES

FIGURE 10.5.7-2

ALASKA LNG

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10.5.7.2 West Dock Navigational Channel Alternatives

As depicted in Figure 10.5.7-3, the shape of Prudhoe Bay, and the seafloor limit the number of practical dockhead location alternatives to an area extending north to northeast from STP. The proposed dockhead was chosen to eliminate dredging a channel and minimize causeway expansion.

10.5.7.3 Barge Bridge Alternatives

The existing bridge across the 650-foot-long breach is limited to single-lane light vehicle traffic at a width of 20 feet, and an approximate load limit of 100 tons. A bridge crossing with the capacity to support the module weight would be required for a successful offload and transport from DH 4.

A temporary barge bridge consisting of two barges ballasted to the sea floor to bridge the gap is the Applicants' proposed alternative. The barges would be placed at the beginning of the open-water season prior to each sealift. The barge bridge offers three areas for fish passage: the area between the barges and two areas between each barge and the dock bulkheads. The barges would be removed at the end of each sealift.

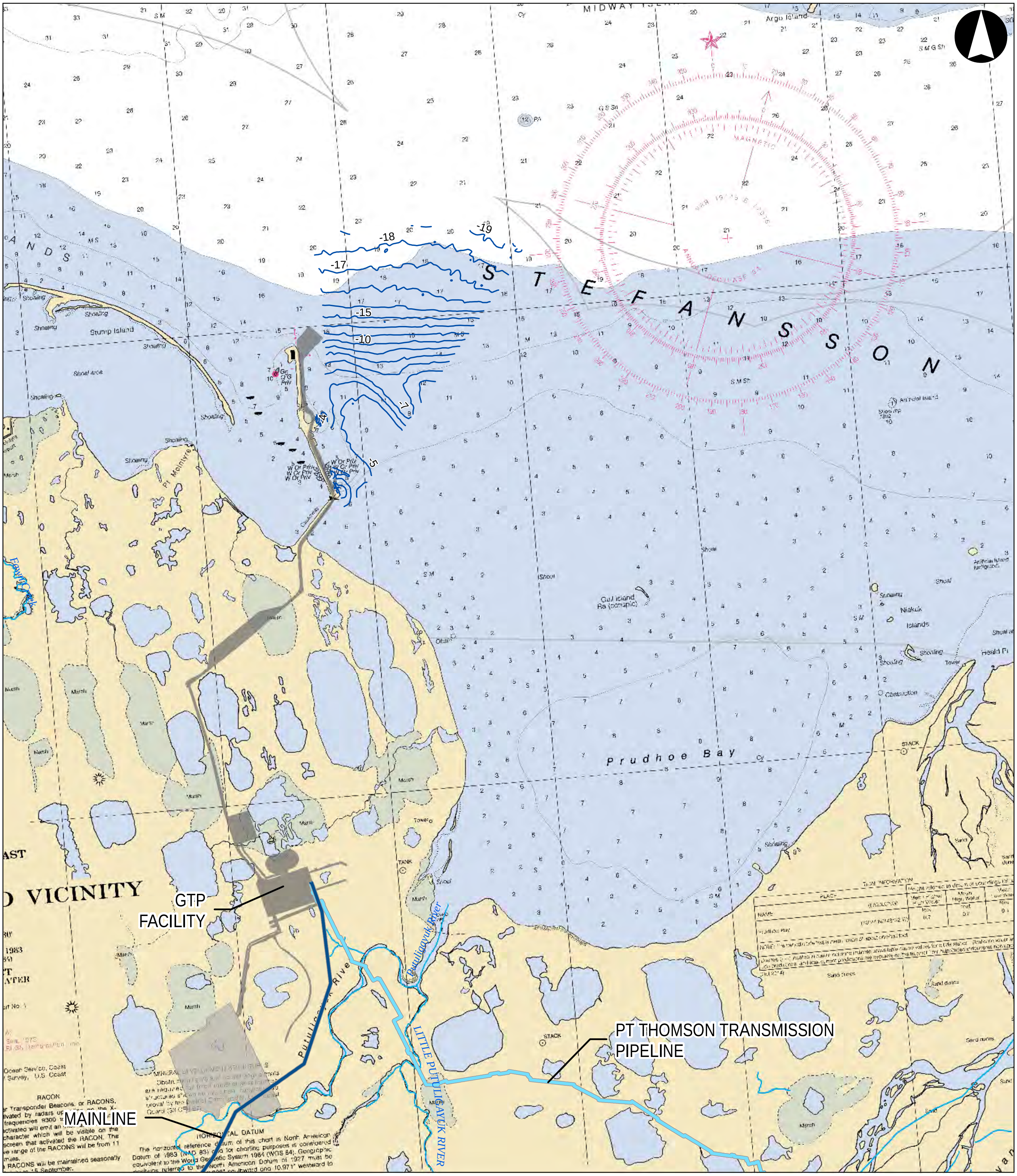
Pre-work would be performed a year before the first sealift to level the sea floor and install breasting dolphins for the barge bridge support. Work would be performed each sealift year to maintain the seabed level for ballasting the barge bridge into position.

In addition to the barge bridge (the proposed alternative), three other options were considered:

- Deck Bridge – This consists of a permanent structure and allows for fish passage. The installation of this bridge would require an extensive construction period with potential for high noise activities, especially for a large quantity of driven piles, and may have the most impact to marine life;

- Granular Material Bridge – This bridge would be installed as a permanent structure. The bridge would consist of culverts to allow for fish passage. Design issues related to ice strengthening of the bridge, ice blockage of culverts, and other technical issues have not been fully progressed. Damage to culverts could block fish passage with limited opportunity for maintenance or repair; and

- Ice Bridge – This is the least feasible alternative because it is a temporary seasonal bridge that requires 40+ acres for a staging area. The ice bridge may not have the capacity to support the 9,400-ton modules. There are no known prior attempts to use ice bridge for loads this heavy. There are also concerns with usage of the SPMTs during the coldest winter months, because the SPMTs would have to be upgraded to Arctic-rated hydraulics and hydraulic oils, increasing the potential risk of hydraulic fluid release.



X:\AKLNG\Resource Reports\RR10\Figure 10_5_7-3 - Bathymetry of Prudhoe Bay.mxd

LEGEND

- Alaska LNG Rev C2 Route
- Point Thomson Transmission Line
- Bathymetry Contours
- Major Rivers
- GTP Facility
- Study Area

0 0.5 1 2 Miles

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PREPARED BY:	AGDC		
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DATE:	2017-03-09	SHEET:	1 of 1

BATHYMETRY OF PRUDHOE BAY

FIGURE 10.5.7-3

ALASKA LNG

10.6 CONSTRUCTION ALTERNATIVES

10.6.1 Onshore Pipeline Construction Alternatives

10.6.1.1 Mainline

Although there is essentially only one way to install a pipeline below grade for 807 miles through diverse terrain (dig a ditch and install the welded pipe, and backfill the ditch), there are different ways to accomplish this construction activity over the seasons and years.

Based on lessons learned from the construction of TAPS and the anticipated constraints imposed by worker safety, weather, ground conditions (excavation methods and speed), and day length, the Applicant considered the length of pipeline that needs to be completed (hydrotested and final tie-ins) in a given construction year. Based on the lessons learned from TAPS and evaluation by construction personnel, a goal was established that no more than 80 miles of pipe should be laid per construction season (summer or winter). Each construction year for the Project is considered to consist of two construction seasons (a winter and summer season). With these goals in mind, the optimal spread lengths necessary to install 80 miles per season were determined. The length of a spread, and the segments within a spread, are dictated by the anticipated length of the summer and winter season in that geographic location. The drivers that dictate where to place the segment and spread breaks are:

- Using proven technology and construction methodologies available for pipeline construction in Arctic and Subarctic physiographic regions – This includes lessons learned from recent TAPS construction, work in Canada, and test trials of trenching and topsoil stripping in Arctic conditions in Alaska.

- Practicable Logistics execution – This includes placing camps in a manner that minimizes the socioeconomic and environmental impact as well as minimizes the number of moves each camp is required to have to effectively support construction activities and minimize transportation distances for the crews. Practicable logistics also includes identifying available access roads, locations for staging areas, getting materials and equipment from outside of Alaska to the construction site in a timely manner with minimal disruption of residents and tourists, and the availability/location of cost-effective resources necessary for construction (granular material, water, sand, disposal areas, etc.).

- Practicability – This entails developing a construction plan that can be safely and realistically completed within the design limits of people and equipment. An assessment of the limits of workers and the machines available to construct the pipeline is made to ensure that a construction plan does not put workers in unsafe situations or pushes the limits of the equipment to unsafe conditions in which they were not designed to work.

- Cost-effectiveness – The cost of delivery must be competitive in the world marketplace to fulfill the Project purpose and need. Extending construction over many years or using construction methods that are too time- or resource-intensive would result in a higher cost. This includes having construction equipment sit idle between seasons or years, sending construction crews back and forth multiple times per year, and/or developing or building specialty construction equipment that would be required to build the pipeline.

Integration across these considerations establishes how many miles can reasonably be built in a given season along each spread. This in turn establishes the length and location of summer and winter construction segments within a spread. Minimizing the number of required construction seasons while safely building the facilities would reduce the overall impact of construction by reducing the number of years/seasons that the ground is disturbed, as well as construction traffic conflicts with existing users of the roads, railroads, and waterways.

Alternative construction plans considered for the Mainline are listed in Table 10.6.1-1. As described in Section 1.5.2.3 of Resource Report No. 1, the Applicant's proposed construction plan would use four construction spreads that would build (lay) the pipeline during two consecutive years. Each construction year would consist of one winter (W) construction season and the following summer (S) construction season; therefore, the proposed Mainline two-year construction schedule with four spreads consists of four construction seasons in a W-S (winter-summer) schedule. Scheduling portions of the ROW for winter construction avoids impacts to tourist areas, subsistence hunting and gathering, wildlife, and wetland impacts. Keeping construction equipment busy over the following summer reduces the overall time to construct the Project (as opposed to waiting till the next winter), reducing the duration of impacts to the minimum number of years (two) possible without inundating the state with pipeline construction work spreads.

TABLE 10.6.1-1

Alternative Mainline Construction Plan Comparison

Construction Plan Scenario (Spreads and Seasons)	Description	Spreads	Pipe Lay Seasons	Pipe Lay Season Configuration	Construction Years	Comments
Proposed Construction Plan (Scenario F; 4-and-4)	Four spreads and four seasons resulting in 16 construction sections averaging 49 miles	Four	Four	Four Spreads: Each season for each year (summer and winter for two years)	2.5	Most cost-effective layout of equipment and construction schedule; good allocation of winter/summer relative to terrain; every season worked by every spread; high likelihood of finishing on schedule based on number of miles to complete per season
Scenario A (4 and 3)	Four spreads and three seasons resulting in 12 construction sections averaging 65 miles/season (98 miles per year)	Four	Three	One Spread: W-S-W Three Spreads: S-W-S	2.5	The longer construction sections pose a higher risk for completion of a segment within a given construction season. Confining the overall plan to a S-W-S scenario (as opposed to W-S-W-S) allows only one winter season, which increases risk of adequate preparation for the ensuing summer work season. This would mean clearing all the vegetation for the ensuing summer season in one winter, while construction all of the winter segments. Only one winter season also means less ROW is completed during the winter to avoid fishery, wetland, tourism, and subsistence conflicts.
Scenario C (Uneven 5 and 3)	Five spreads and three seasons with uneven spread breaks to allocate longer winter seasons in the northern spread resulting in 16 construction sections averaging 49 miles/season (78 miles per year)	Five	Mostly three One spread with four	One Spread: W-S-W Three Spreads: S-W-S One Spread: W-S-W-S	2.5	Four seasons with no construction in some of the spreads; longer winter sections south of the Brooks Range (i.e., peaking at 58 miles south of the Brooks Range) poses a higher risk for unanticipated challenges that could compromise the ability to complete construction production targets within the construction season; extra cost of fifth spread with little benefit (i.e., does not shorten the overall construction duration)
Scenario C (Even 5 and 3)	Five spreads and three seasons with evenly spread breaks resulting in 16 construction sections averaging 49 miles/season (78 miles per year)	Five	Mostly three One spread with four	One Spread: W-S-W Three Spreads: S-W-S One Spread: W-S-W-S	2.5	Four seasons with no construction in some of the spreads; longer winter sections south of Brooks (i.e., peaking at 55 miles south of the Brooks Range) poses a higher risk for unanticipated challenges that could compromise the ability to complete construction production targets within the construction season; extra cost of fifth spread with little benefit (i.e., does not shorten the overall construction duration)

TABLE 10.6.1-1

Alternative Mainline Construction Plan Comparison

Construction Plan Scenario (Spreads and Seasons)	Description	Spreads	Pipe Lay Seasons	Pipe Lay Season Configuration	Construction Years	Comments
Scenario E (NS+3 and 4)	Three spreads and four seasons plus the North Slope contractor doing the northernmost section resulting in 13 construction sections averaging 60 miles/season (120 miles per year)	Three	Four	All Spreads: W-S-W-S	2.5	Winter sections are too long to be completed in a given winter based on anticipated lay rates; factoring in the northernmost section of the Mainline being done by the Point Thomson contractor does not make the three-spread and four-season construction plan more favorable (i.e., 13 construction sections averaging 60 miles and the yearly total that has to be completed is high, 120 miles).
Scenario G (NS+4 and 4)	Four spreads and four seasons plus the North Slope contractor doing the northernmost section resulting in 17 construction sections averaging 46 miles	Four	Four	All Spreads: W-S-W-S	2.5	Reduces winter risk somewhat on average but not for the longest winter sections; they are similar length as in Scenario F

Notes:
NS=North Slope
W=winter construction
S=summer construction

With the proposed construction plan of four spreads and four seasons, optimal assignment of seasons per spread was based on the following criteria:

- Soil conditions – Thaw-unstable permafrost, wet surface soils, high ground water, bogs;
- Terrain considerations (i.e., steep and hilly versus flat areas);
- Water and material source availability;
- ROW accessibility;
- Seasonality constraints (e.g., anadromous streams);
- Potential for resource sharing (e.g., camp sharing between spreads);
- Which side the working side resides (pipe lay direction); and
- ROW construction mode and cost (e.g., frost packed, winter work pad).

10.6.1.2 PTTL

Aboveground pipelines on the Arctic Coastal Plain are traditionally constructed during the winter. Based on lessons learned from previous pipeline construction (e.g. Point Thomson Export Pipeline), the drivers that impact segment and spread breaks are:

- The number of road, pipeline, and utility crossings (e.g., extent of developed versus undeveloped areas);
- Travel distance/time between the camp and active work area; and
- The cost of supporting a large camp over one winter season versus a smaller camp over two winter seasons.

Alternative construction plans considered for the PTTL are listed in Table 10.6.1-2. As described in Section 1.5.2.3.2.2 of Resource Report No. 1, the proposed construction plan for the Project would be completed in two pipeline construction spreads working over one winter season to install the VSMs and the pipeline from an ice workpad. Hydrostatic testing and restoration would occur the following summer.

TABLE 10.6.1-2

Alternative PTTL Construction Plan Comparison

Construction Plan Scenario (Spreads and Seasons)	Description	Spreads	Comments
Scenario 1 – Proposed Construction Plan	Two spreads and two seasons	2	W1 season to install the VSMs and pipeline. Hydrostatic testing and restoration would occur in S1.5.
Scenario 2	One spread and three seasons	1	W1 would be for installation of VSMs, W2 for installation of the pipeline, and S2.5 would be for hydrostatic testing. This is how the existing Point Thomson Export Pipeline was constructed.

10.6.2 Offshore Pipeline Construction Alternatives

Factors that influence alternative methods of offshore construction of the Mainline include, but are not limited to:

- Tidal range – The tides in Cook Inlet are semidiurnal, with two unequal high tides and two unequal low tides per day, and a tidal range from 20 feet to 30 feet. The resulting tidal currents are significant in Cook Inlet, with mean current speed ranges from approximately 1.9 feet/second (1.1 knots) to 8.1 feet/second (4.8 knots) near the seabed to approximately 2.4 feet/second (1.4 knots) to 10.1 feet/second (6.0 knots) at the water's surface, with the flow predominantly following the centerline of the Inlet. These currents impact the type of equipment that can be used in Cook Inlet, the amount of time per day equipment can operate, and the orientation of the equipment with respect to peak currents;

- Sea ice – The buildup and movement of winter ice limits the working windows for vessels in the Upper Inlet to the ice-free season. Based on metocean conditions, the available window for offshore pipeline installation in Cook Inlet is expected to span approximately six months from mid-April to mid-October;

- Marine wildlife and fisheries – A complete discussion of marine wildlife in Cook Inlet is provided in Resource Report No. 3. The Mainline route crosses Beluga Whale CHA 2. The presence of the critical habitat as well as other marine mammals would impose operations restrictions during construction, further limiting the workday. In addition, there are drift net fisheries in the Project area. Construction of the pipeline would impose some restrictions on vessel traffic around the construction vessels as they move across the Inlet; and

- Marine traffic – Vessel traffic greater than 300 gross tons calling on middle Cook Inlet is primarily tank ship activity in and around the Nikiski and Drift River terminals. The fishing fleet in the area consists of commercial fishing vessels and sport charter vessels. In addition, there are also small commercial freight vessels, personal use pleasure craft, and tourism vessel traffic in the Project area. As noted, construction of the pipeline would impose some restrictions on vessel traffic around the construction vessels as they move across the Inlet.

Based on the size and weight of the pipeline, the traditional methods of building the pipeline onshore and towing it out into the Inlet (as has been done for other pipelines) would not be feasible in this case. Each 40-foot joint of pipe would weigh more than 33 tons with the concrete coating required to counteract buoyancy. Current vessels used to construct pipelines could not pull more than 1 to 2 miles of such pipe welded together. Therefore, the pipeline would be welded on a construction barge, called a lay barge, and the pipe lowered over the back end of the barge. The barge is moved forward as each joint of pipe is welded to the end. This results in the pipe coming off the lay barge and forming a curve down to the seabed from the back of the barge to where it is laid on the bottom. After each piece of pipe is welded to the string, the barge is moved forward from its position by winching in the anchor cables. This type of pipe laying technique is called the "S-lay" pipeline construction for crossing large bodies of water.

10.6.2.1 Lay Barge Alternatives

The Applicant evaluated the use of a conventionally moored versus dynamically positioned (DP) lay barge for offshore pipe lay within Cook Inlet. A conventionally moored vessel uses multiple winches and anchors for holding location. In contrast, the position or location of a DP vessel is maintained by a propulsion and station-keeping system that is typically interfaced with a satellite-based geographic positioning system (GPS). The DP system consists of hull-mounted thrusters near the bow, at midship, and at the stern, which are operationally controlled by a shipboard computer system (PetroMin Pipeliner, 2012).

The primary impact of the tidal currents within Cook Inlet would be on the pipelay vessel's ability to stay in position while it is welding pipe together. It would also impact the movement of the anchors that hold the pipelay vessel in position. To successfully lay the pipeline and control vessel position while safely holding and managing a long string of welded pipe, the vessel must be able to successfully hold its position in the anticipated environmental conditions.

Recent analysis indicates that there are pipelay vessels that have the mooring and tension capacity to hold station in the high current/tidal environment of Cook Inlet, while simultaneously laying large-diameter, heavy-wall pipe. However, the number of available vessels is limited. Furthermore, the analysis highlights that DP vessels would not be capable of holding station in Cook Inlet with DP alone and require the use of anchors to supplement their station keeping during pipe lay.

A comparison of these two vessel types – conventionally moored versus DP lay vessel – is provided in Table 10.6.2-1. The use of the bottom pull method by barge pull-out is not considered to be feasible for the Project, and it was dismissed as an alternative.

The pipelay vessel would need to be able to achieve forward progress to continue pipelay operations. During high current periods, it may not be possible to relocate anchors or move the vessel along the route using an anchor lay barge until the current subsides from peak flow. To overcome these environmental conditions, the mooring analysis indicates that large anchors in addition to high-capacity winches on the pipelay vessel would be required. DP, while operationally favorable to avoid anchor handling, is not considered suitable to operate in high current conditions without some supplemental method of maintaining position while pipe laying. Using DP pipelay-capable vessels along with an anchor system may provide superior vessel station-holding capability and would also be considered because:

- Cook Inlet is generally shallow in nature and has a large tidal range that produces high currents. The use of standalone DP vessels is not considered to be a feasible approach because they cannot maintain station in the high currents. DP thruster use is also limited in shallow water depths where reduced vessel draft is required (some DP vessels require 65 feet of water in which to work). Generally, the pipeline would be placed in water less than 100 feet deep (with the exclusion of a few locations across the route).

- The use of DP thrusters, when possible, greatly reduces the mooring load demands thus making the operation safer and more productive.

- Minimal long-term impacts to benthic habitat are anticipated. (Details of the benthic habitat and dynamic nature of Cook Inlet are further described in Resource Report Nos. 2 and 3).

- The known fact is that the larger the vessel, the greater the target area presented to wind, wave, and current forces; the heavier the vessel, the higher the holding requirements would be for a conventionally moored lay barge. The offshore pipeline construction contractor would be required to use a barge mooring system to accommodate Cook Inlet's extreme currents and large tidal fluctuations. In addition, support vessels would remain in proximity for the duration of construction.

One of these pipelay vessels would be selected once the procurement process has been undertaken and the contractors provide the potential vessels that can accomplish the requested work scope.

TABLE 10.6.2-1

Comparison of Lay Barge Alternatives for Construction of the Offshore Portion of the Mainline

Factor			**DP Lay Vessel with Anchor Moorings (Applicants' Proposed Alternative)**	**Conventionally Moored Lay Vessel**
Engineering/ Technical Considerations	Mooring Considerations		Pipelay may be limited in high current periods; should be shorter duration of limitation	Pipelay may be limited in high current periods.
	Typical Water Depths		Generally not used in water depth less than 200 feet, but can be used in water depths as shallow as 60 feet	Typically used for pipelay in shallow water
	Position Maintenance	System	Hull-mounted thrusters near the bow, at midship, and at the stern, interfaced with GPS and under computer control Additional anchoring support required; 8–10 anchors considered reasonable based on known DP pipelay vessels available worldwide.	Anchors[a,b] Smaller lay barges (e.g., 400 feet long by 100 feet wide), typically require eight anchors. Larger barges operating in deeper water typically require 12 anchors (3 anchors per quarter). This may be increased to 16 anchors for Cook Inlet.
		Required Support Vessel(s)	Two to three anchor-handling tugs would be required to handle anchors.	Typically two anchor-handling (deploy-and-retrieve) vessels depending upon water depth Up to four anchor handling tugs may be required.
Environmental Considerations	Sea Floor Disturbance		Short-term impacts from anchors and cable sweeps[c] would disturb the bottom. Recovery of the benthic habitat is anticipated to be rapid due to the highly dynamic nature of surficial sediments in Cook Inlet. Turbidity and sediment movement are typical of Cook Inlet, and the associated benthic fauna are anticipated to be adapted to these conditions. A reduction in potential area of disturbance is expected with fewer anchors being used than with a conventionally moored barge; however, the number of anchors cannot be determined until a vessel is selected in the bid process.	Short-term impacts from anchors and cable sweeps[c] would disturb the bottom. Recovery of the benthic habitat is anticipated to be rapid due to the highly dynamic nature of surficial sediments in Cook Inlet. Turbidity and sediment movement are typical of Cook Inlet, and the associated benthic fauna are anticipated to be adapted to these conditions. The potential area of disturbance is 1,212 acres.

TABLE 10.6.2-1

Comparison of Lay Barge Alternatives for Construction of the Offshore Portion of the Mainline

Factor		**DP Lay Vessel with Anchor Moorings (Applicants' Proposed Alternative)**	**Conventionally Moored Lay Vessel**
	Air Quality	To remain on station during a pipeline installation, a DP vessel must constantly operate its hydrocarbon fuel-consuming propulsion system; expected to be a high level of operation based on the extreme currents and large tidal fluctuations in Cook Inlet. Tug assistance to move from station to station during an installation project and the requirement for the services of anchor-handling vessels to deploy, retrieve, and redeploy anchors contribute to the pollutant emission levels	Power generation would continue during the operations of construction. The pipelay vessels main engines would not be used while on station. Tug assistance to move from station to station during an installation project and the requirement for the services of anchor-handling vessels to deploy, retrieve, and redeploy anchors contribute to the pollutant emission levels.
	Sound	Thrusters generate noise and a DP vessel is anticipated to generate a relatively higher sound level and longer duration of sound, due to the continued use of the thrusters to hold position, which are expected to have a high level of operation based on currents and tidal fluctuations in Cook Inlet. It is possible that NMFS may require an Incidental Harassment Authorization for thruster sound signatures.	Pipeline installation vessels that are fixed by anchors have been found to generate lower sound levels than their support vessels and associated anchor-handling vessels, which generate higher sound levels due to the use of thrusters and engines for propulsion. However, none of the vessel noise is anticipated to require an Incidental Harassment Authorization or Letter of Authorization for Marine Mammal Protection Act impacts.
	Temporary Visual Impact	The pipelay vessel would be supported by anchor handling tugs (two to three), pipe supply vessels (two), and a survey vessel.	The pipelay vessel would be supported by anchor handling tugs (two to four), pipe supply vessels (two), and a survey vessel.
Vessel Traffic Considerations	Notice to Mariners	The Southwest Alaska Pilots Association (SWAPA) and USCG would be routinely consulted during construction planning and execution. USCG would provide notices to local mariners indicating the position of the construction and support vessels.	SWAPA and USCG would be routinely consulted during construction planning and execution. USCG would provide notices to local mariners indicating the position of the construction and support vessels.
	Potential for interruption of vessel traffic, including recreational and subsistence use	Would require an exclusion zone roughly 1 mile in diameter around the vessel. Pipelay vessel rate of travel is expected to be less than 1 mile per day so mariners would have sufficient leeway to plan their passing routes if the vessel is located in a heavy traffic area.	Would require an exclusion zone roughly 1 mile in diameter around the vessel. Pipelay vessel rate of travel is expected to be less than 1 mile per day so mariners would have sufficient leeway to plan their passing routes if the vessel is located in a heavy traffic area.

10.6.2.2 Marine Pipeline Installation and Burial Alternatives

Marine (offshore) pipelines can be laid directly onto the seabed or buried below the seafloor. Concrete weight coating can be used (for either alternative) to enhance the pipeline protection and on-bottom stability. Direct pipelay results in the smallest footprint disturbance to the seafloor compared to any burial technique. The Project representatives provided technical updates to PHMSA in April and October 2015 related to the direct lay of the marine pipeline segment. PHMSA has verbally taken no objection to the Project's interpretation of Cook Inlet as offshore. A "Request for Interpretation" has been submitted to ADOT&PF to clarify that Cook Inlet is considered Offshore in the context of PHMSA's regulations per Code of Federal Regulations (C.F.R.) 192 and that heavy concrete weight coating satisfies the cover requirements of C.F.R. 192 (see Resource Report No. 1, Appendix D).

If a marine pipeline is buried below the seafloor, several methods exist. These methods are described as follows:

- Submarine plow – A submarine plow is towed along the pipeline after it has been laid on the seafloor. The plow side-casts material and simultaneously lowers the pipe into a trench. Multiple passes may be required to reach the required burial depth. The plow is then reversed and dragged along the trench line, refilling the trench with the material cast out during the first pass, if required;

- Jet sled – A jet sled is towed, straddling the pipeline after it has been laid on the seafloor. The jet sled has built-in high-pressure seawater jets that open a trench in the seabed underneath the pipeline as it is towed along. The seafloor material is loosened by the jets and is entrained by suction tubes and expelled behind the sled covering pipeline as it moves. Multiple passes may be required to reach the required burial depth. The lay barge provides the pressurized seawater and air for the jet sled system;

- Hydraulic Cutterhead (Suction) Dredge – A cutterhead dredge is a hydraulic suction dredge with a rotating cutterhead attached to the intake to mechanically assist in the excavation of consolidated material. Dredged material is pumped from the head through an intake line and then placed in a hopper or pumped to a predetermined discharge point. Suction dredges come in various forms, primarily of either a cutterhead suction or trailing suction head dredge. The dredge vessel is used ahead of the pipelay barge to create a pre-constructed trench. Using the lay barge, the pipeline is then subsequently placed in the pre-constructed trench and backfilled using either the dredged material or imported fill; and

- Mechanical dredge – A barge-mounted clamshell and excavator (i.e., backhoe) are typical mechanical dredges. These mechanical devices use a bucket, and in the case of a clamshell, a crane, to excavate the sea floor material. The dredge barge is used ahead of the pipelay barge to create a pre-constructed trench. Using the lay barge, the pipeline is then subsequently placed in the pre-constructed trench. During mechanical dredging, the excavated material is side-cast and then later relocated to backfill the trench.

It is anticipated that the high-velocity currents in Cook Inlet would rapidly fill a pre-dug trench with sediment before the pipeline could be placed in it. Although considered for limited use at the shore approaches, the use of either the hydraulic suction dredge or mechanical dredge alternative was not considered feasible for burial of the Mainline. These methods would tend to pose many significant challenges (e.g., maintaining position on the route as the trenching is done) to successfully bury the pipeline in Cook Inlet. In addition, both cutter suction and mechanical dredge methods would result in the largest impact from a sea bottom and sedimentation perspective as well as increased noise during pipeline burial. When coupled with summer construction, burial of the pipeline would create a larger impact to fisheries and marine mammals.

The Applicants' proposed alternative for the Project is the use of direct pipelay, without burial. This is consistent with recent pipeline installations (such as the offshore pipeline for the Kitchen Lights Project) in Cook Inlet and with consideration to the burial success rate of historic pipeline installations. High current velocities and turbulence keep fine sediments in suspension in Cook Inlet. As a result, bottom sediments throughout most of the Inlet are predominantly coarse-grained (i.e., cobbles, pebbles, and sand) with only minor amounts of silt and clay. In some areas, rock or sorted glacial material is also present. These materials prevent the jet sled or plow from effectively burying the pipeline below the sea bottom. While burying pipelines in Cook Inlet is not the customary practice for the industry, burial options are still being investigated.

A comparison of the viable installation and burial methods is provided in Table 10.6.2-2.

TABLE 10.6.2-2

Comparison of Alternative Pipeline Installation and Burial Methods for the Offshore Portion of the Mainline

Factor		**Direct Lay (Applicants' Proposed Alternative)**	**Jet Sled**	**Submarine Plow**
Engineering/ Technical Considerations	Feasibility	Suitable for all bottom types	Generally suitable for loose sediment, but not feasible for hard-packed sediments or rock	Generally suitable for loose sediment, but not feasible for hard-packed sediments or rock
	Need for Additional Structure	Armoring and/or anchoring	Typically none, unless there are areas armored for scour protection or that are above grade due to presence of hard bottom	Typically none, unless there are areas armored for scour protection or that are above grade due to presence of hard bottom
	Safety	More susceptible to anchor impacts and collision, unless armored The design basis of the offshore portion of the pipeline would be concrete-coated for protection and to ensure on-bottom stability.	Reduced susceptibility to anchoring impacts and collision	Reduced susceptibility to anchoring impacts and collision
Environmental Considerations	Seafloor Disturbance	Minimal footprint impact on seafloor	The area of seafloor disturbed by the burial process is typically just slightly wider than the outside diameter of the pipeline. Multiple passes may be required to achieve the required burial depth resulting in multiple, repetitive anchor drops/cable sweeps.	The area of seafloor disturbed by the burial process is typically just slightly wider than the outside diameter of the pipeline. Multiple passes may be required to achieve the required burial depth resulting in multiple, repetitive anchor drops/cable sweeps.

TABLE 10.6.2-2

Comparison of Alternative Pipeline Installation and Burial Methods for the Offshore Portion of the Mainline

Factor		**Direct Lay (Applicants' Proposed Alternative)**	**Jet Sled**	**Submarine Plow**
	Turbidity	Anticipated to result in the smallest amount of turbidity of the three alternatives	Generally creates more temporary turbidity in the water column than a plowing device	Generally creates less temporary turbidity in the water column than a jet sled
	Sound	Predominantly vessel-generated sound	Predominantly vessel-generated sound; no motors or compressors would be located in the water The motor for the jet sled would be located on the deck of the lay barge	Predominantly vessel-generated sound; no motors or compressors would be located in the water
	Migratory Species	Potential to affect migration of demersal species (e.g., fish, crustaceans) across Cook Inlet; potential to act as a fish attracting device	No effect anticipated	No effect anticipated
Source: Genesis Oil and Gas Consultants, 2011; PetroMin Pipeliner, 2012				

10.6.2.3 Cook Inlet Shoreline Crossing Alternatives

As discussed in Section 10.4.2, the shore crossings for the Cook Inlet crossing are located at Shorty Creek to the north and Boulder Point to the south. Each of these shore crossings will extend out to a water depth between 35 to 45 feet MLLW. The final depth at which the shore crossings terminate will be constrained by the following:

- The length of the pipe that can be pulled offshore by the pull barge;
- The draft constraints of the selected laybarge; and
- The burial distance required to protect the pipeline from anticipated hazards.

The criteria for selecting these crossing locations include:

- A reasonably clear level area on land, atop the bluffs, for pull-in preparation or to support the winch that could pull a pipeline from offshore;
- Sufficient water depth, close enough to shore to be within capacities of a barge-mounted winch to pull the pipeline from shore without requiring significant buoyancy being attached to the pipeline, which requires a larger trench;
- Ground conditions suitable for excavation using standard trenching and dredging equipment; and
- The ability to access and maneuver close to shore with a suitable pipe-laying vessel without relying on dredged access (deep water close to shore).

Three commonly used construction methods were evaluated for the shore crossings:

- Open-cut trench – A standard method of installing pipelines into a pre-excavated trench. The trench is created using excavation or dredging equipment and the excavated material is stored for backfilling, where applicable. There are two forms of this open-cut method—the pipeline would be welded and pulled from a lay barge offshore, or the pipeline would be welded onshore and pulled from a barge offshore;

- HDD – A description of the HDD method of installation is found in Section 1.5.2.3.4.1 of Resource Report No. 1; and

- Direct Pipe – The direct pipe method combines the more established methods of microtunneling and HDD. Similar to boring under a road and pushing a welded pipeline through the borehole, soil or rock would be removed by a slurry microtunneling machine at the same time that pipeline is pushed into the ground. However, unlike traditional microtunneling, the direct pipe method incorporates a steerable cutterhead located at the tunnel face. Cuttings would be mixed with the slurry in an excavation chamber and then pumped through the pipeline to a separation plant at the entrance point of the tunnel. Cuttings would be separated from the drilling slurry and disposed of offsite and the drilling slurry reused.

A comparison of these methods is provided in Table 10.6.2-3. Although the open-cut methodology with a pull barge is the Applicants' proposed alternative for crossing, the Applicant is continuing to investigate the geotechnical and geological conditions at each crossing. A decision on the construction methods will be finalized upon completion of these studies.

TABLE 10.6.2-3

A Comparison of Alternative Shore Crossing Methods

		Alternative Shore Crossing Methods		
Criteria		**Open-Cut Trench (Applicants' Proposed Alternative)**	**Direct Pipe**	**HDD**
Engineering/Technical Considerations		Suitable for most ground and soil conditions, except for oozing mud and running sands Requires sufficient pipe weight to maintain on-bottom stability	Feasible in most soil conditions Length limitations, not a standalone solution Shoreline crossing profile versus curvature radius and shaft construction	Highly dependent on soil data; requires extensive geotechnical information for the design (e.g., problematic with granular material) Length limitations, would require open cut or other methods to complete distances over 3,000 feet Feasibility of supporting large-diameter casing in offshore environment Would require offshore jack-up vessel
Environmental Considerations	Shoreline Disturbance	The side slope of the bank would require additional excavation, and steep bluffs would require a large volume of material to be removed, stored, and replaced. The	Would require less disturbance than open cut but still requires shoreline	Would require less disturbance than open cut but still requires shoreline

TABLE 10.6.2-3

A Comparison of Alternative Shore Crossing Methods

Criteria		**Alternative Shore Crossing Methods**		
		Open-Cut Trench (Applicants' Proposed Alternative)	**Direct Pipe**	**HDD**
		general shore cut is approximately 250,000 cubic yards at Shorty Creek and 310,000 cubic yards at Boulder Point. Requires ROW clearing and workspace beyond the estimated 0.7 acre needed for Boulder Point and 0.5 acre at Shorty Creek for workspace	ROW clearing and workspace The onshore pipeline ROW would be 82 feet with additional workspace might be needed on the entry and exit side of the crossing. The proposed cleared area for each crossing, including pipe string make-up areas, is approximately 4.7 acres.	ROW clearing and workspace The onshore pipeline ROW would be 82 feet and additional workspace might be needed on the entry and exit side of the crossing. The proposed cleared area for each crossing, including pipe string make-up areas, is approximately 4.7 acres.
	Seabed Disturbance	Requires nearshore trenching. Based on the bathymetry of Cook Inlet and an assumed burial out to a 41-foot water depth (MLLW), the length of the offshore trench would be approximately 3,200 feet at Boulder Point and 10,000 feet at Shorty Creek. For these assumed crossing distances, the estimated dredging volumes are approximately 115,000 cubic yards for Boulder Point and 355,000 cubic yards for Shorty Creek.	Nearshore trenching effort is reduced by roughly 1,000 to 1,500 feet Requires dredging of the exit pits and offshore trench	Nearshore trenching effort is reduced by roughly 1,000 to 2,000 feet Requires dredging of the exit pits and offshore trench
	Water Quality	Turbidity and sedimentation related to trenching	Reduced turbidity and sedimentation over open-cut trenching; however, there is a potential for drilling mud release	Reduced turbidity and sedimentation over open-cut trenching; however, there is a potential for drilling mud release
	Air Emissions	Multiple (12–18) pieces of equipment operating for 12 or more hours per day Anticipated to have higher emissions than the other alternatives	Will likely have the lowest air emissions due to reduced number of onshore equipment needed, however the drill rig would run 24 hours a day, seven days a week, when the installation begins to keep the pipeline moving.	If an offshore jack-up vessel is used, both the drill and it would need to run 24 hours a day, seven days a week, during installation to avoid collapse of the borehole and would have comparable emissions to open cut. It is anticipated to have higher emissions than direct pipe installation.

TABLE 10.6.2-3

A Comparison of Alternative Shore Crossing Methods

Criteria		Alternative Shore Crossing Methods		
		Open-Cut Trench (Applicants' Proposed Alternative)	**Direct Pipe**	**HDD**
	Sound	General construction sound levels related to dredging	Higher level of sound The Direct Pipe method would produce additional sound at the onshore drilling location because the machinery will be continually running.	Higher level of sound The HDD method would produce additional sound at the offshore drilling location because the machinery would be continually running at this location during the drilling operation.
Practicability of Construction		Bank stability needs to be considered for safety (e.g., sloughing and collapse) and restoration. Eliminates the risk of borehole collapse or the pipe becoming stuck in ground. This should be a major consideration for the Project given the pipe size, resulting loads, geological formations, and seasonality of the work seasons. Minor breakdowns usually do not cause major delays to all activities. The open trench provides easy access to the work. Effect of the current during the shore pull	The pipeline could be installed in one pass while excavating the borehole (no reaming requirements). The pipeline remains in compression during installation, not tension. The risk of losing significant amounts of drilling mud is lower than with HDD. This method uses less drilling mud in the system because the borehole is mechanically maintained open by pipe and an annulus mud system. Additionally, the drilling mud circulation may be eliminated for the final punch-out of the cutting head onto the seabed.	If boulders are encountered during an HDD, there could be considerable problems or delays associated with routing the drill head around the entire area or specific large boulders. It could be impracticable to complete the HDD if boulders cannot be avoided. The offshore tie-in would be a considerable challenge because the required HDD casing entry/exit angles to the seabed coupled with the pipeline stiffness makes the required tie-in points to be at a point well below the mudline, and exit hole in the seafloor can exceed 20 feet deep and 80 or more feet long. Drilling mud could potentially escape from the bore through fissures or fractured ground or spill out at the break-out location when the drilling tool breaks through the ground surface.
Cost		Due to there being no additional support operations and equipment, it would be less expensive than a trenchless operation.	Highest cost because of the cost to use the equipment.	Higher cost than open cut. HDD costs could exceed other options if a jack-up support vessel is required.

10.6.3 Pressure Testing

Once installed, the pipelines (on- and offshore), facility piping, and LNG tanks would be pressure tested in accordance with DOT safety standards (49 C.F.R. 192 and 193) to verify integrity and ensure the ability to withstand the MAOP. Pressure-test media can include water, glycol, nitrogen, or a nitrogen/helium mix.

The Applicant has selected water as the proposed alternative for pressure testing during construction for the pipelines (on- and offshore), the LNG tanks, and other large volume testing requirements. Hydrostatic testing of the pipelines is planned for the summer and fall; however, some testing may also be carried out during the winter. If testing would be done during summer or fall, no additives, including antifreeze chemicals, biocides, corrosion inhibitors, oxygen scavengers, or leak detection tracers, would be added to the test water. Use of another medium that complies with regulatory requirements is not feasible. Use of an alternative gaseous medium (e.g., nitrogen) would only be considered a viable opportunity for the testing of small, low-pressure pipes.

If the pipeline is tested with air, 49 CFR 192.503 would reduce the allowable operating pressure by 15 percent for the current pipeline design basis.

The only practicable way to use pneumatic testing is to design exactly where the test segment would be located and use heavier wall pipe in that location to operate the pipeline at the current design pressure, or a reduction of the Maximum Allowable Operating Pressure, both of which are unacceptable outcomes of using a pneumatic test in a pipeline designed for pressure testing with a liquid.

10.6.4 Dredge Method and Dredge Material Placement Alternatives

10.6.4.1 Dredging Techniques Alternatives

Several methods for large-scale dredging are currently used worldwide, and in a variety of climates. The following dredging methods are commonly used independently or in combination:

- Hydraulic Dredging – As noted in Section 10.6.2.2, cutterhead dredges use rotating cutters and hydraulic means (pumps) to move dredge material from the seafloor into a discharge pipe.

- Mechanical Clamshell Dredging – A mechanical clamshell dredge consists of a barge-mounted machine with a clamshell bucket that cuts sediment from the seafloor and raises it through the water column. The sediment is then typically transferred to a hopper barge. The hopper barge is towed to a disposal location where the dredged materials are then released onto the ocean floor. Clamshell dredging is a widely used dredging method and works with many soil types; however, it is less suitable to silty soils.

- Barge-Mounted Excavator – Excavators are mounted on barges and dredge to the required depth. Dredged material is typically transferred to the disposal site via barge and released onto the ocean floor. This method is widely used and works with many soil types, however it is less suitable to silty soils.

- Elevated Excavator – This method of dredging use excavators that can elevate the cab and can motor above the waterline, while the tracks remain underwater. This method is suitable for shallower water and in combination with a barge-mounted excavator to dredge deeper water.

The dredged material is typically transferred to the disposal site via barge and released onto the ocean floor.

- Hydraulic Dredging with Integrated Hopper – Hopper dredges use hydraulic means (pumps) to move dredge material from the seafloor to a hopper. The dredge (dredge and hopper) transits from the dredge location to the dredge material disposal location. This method can achieve high rates of dredge production and typically requires fewer support vessels, because it is a self-contained dredger and hopper. At shallow water depths, this option would be the least feasible.

- Winter Through-Ice Dredging – This method of dredging is conducted in the winter on sea ice in certain locations where the ice is stable for long durations. Equipment is used to remove the sea ice and excavators and then remove the sediment from the seafloor. The sediment is loaded onto dump trucks and transported to the disposal site. Ice roads are constructed to provide access. In locations where ice is not grounded to the seafloor, the ice road and working areas need to be thickened as necessary to support the heavy machinery.

Dredging options were evaluated for excavation of material at the Marine Terminal to dredge the approach and berths. The Applicant will prepare sampling plans for Cook Inlet for potential dredging locations for USACE and U.S. Environmental Protection Agency review prior to sampling.

The feasibility of a particular dredging method depends on (1) the timeframe (i.e., season) during which the dredging and material placement can successfully be accomplished, (2) the type of material being dredged, (3) the available methods for dredged material transport, and (4) the availability of dredged material placement locations. Sediment sampling would be conducted in Cook Inlet in support of potential Project dredging.

10.6.4.1.1 Marine Terminal

Vessel-based marine construction activities, including dredging and dredge disposal, are planned to occur in Cook Inlet between April and October each year, generally considered to be the “open-water” season. This seasonal window is typical for most construction activities occurring in and around Cook Inlet, and provides a number of distinct advantages for the Project over the winter season because it minimizes the risk to life, property, and the environment from the work activities. Although, during certain years, the weather conditions during the months of March and November may allow marine construction activities in Cook Inlet, any vessels that are contracted from outside of Alaska and that are to be used for projects elsewhere during winter months would likely refrain from conducting work in March and November in Cook Inlet to avoid or minimize the potential for encountering winter storms during their transit across the Gulf of Alaska.

Safety of the workforce is of paramount importance. Conducting dredging during the summer months reduces personnel exposure to potentially hazardous conditions that do or could occur during winter months, primarily dynamic sea ice conditions in the dredge area, which can include large sea ice floes, beach or shore-fast ice, and stamukhas. Dredging equipment and support vessels are not typically ice-strengthened or designed to operate in ice conditions. Vessel transit for dredge material disposal would also increase the risk of potential incident. The ice that occurs in the dredge area moves with the large tides and strong currents and is not completely shorefast or bottomfast ice. The ice is therefore not conducive for use as a stable work platform for dredging, as is proposed at West Dock in Prudhoe Bay. In the event of a maritime casualty or other emergency situation requiring rescue or salvage, emergency response capabilities would also be more limited during the winter months.

Furthermore, the potential environmental and operational risks related to conducting dredging during the summer months rather than winter months are considered manageable with mitigation, particularly given that the planned dredging scope is similar in magnitude to other dredging activities conducted in Cook Inlet. Simultaneous operations would be managed with other commercial activities in the vicinity through communication and coordination of work activities. The density of marine mammals at the specific location of dredging is considered to be low, and the dredged area is small when compared to the total area of habitat available in Cook Inlet. The endangered Cook Inlet beluga whale distinct population segment may transit through the area en route to summer feeding grounds, but the dredged area is not known to be a common area for critical life processes, including calving, mating, or feeding. Potential effects of turbidity to other species, including fish, are expected to be minimal given the existing high natural turbidity of Cook Inlet waters.

Shore-based dredging during the winter was not extensively evaluated because the full extent of the dredged area would not be accessible from shore, and shore-based dredging during winter months presents many of the same challenges and potential hazards.

10.6.4.1.1.1 Equipment Selection

Mechanical and hydraulic dredging methods were evaluated for use for dredging the approach channel and berths at the planned MOF during the Project's construction phase. As noted in Section 10.6.4.1, mechanical dredgers use a device such as a bucket to "scoop" dredged material and lift it through and out of the water column. Examples of mechanical dredgers include bucket dredgers, clamshell (grab) dredgers, and backhoe/dippers. The mechanical dredging equipment would be secured on vessels or barges that would be anchored to the seafloor to provide a stable working platform. Various bucket sizes may be used. Sediment removed by mechanical dredge would be placed in split hull or scow/hopper barges and transported by tug to the location of dredge material placement. Hydraulic dredgers apply suction to the dredged sediment, transporting the slurry of water and sediment out of the water column through a pipeline. The dredged material would be pumped from the dredge as a slurry to the disposal location or pumped into split hull barges for decanting and transport to the dredged material placement location.

Comparison of Mechanical and Hydraulic Dredgers

Considerations for the selection of dredging equipment include the suitability of the equipment for handling the physical properties of the in-situ sediment, the scope of dredging (i.e., the spatial extent, depth, and total volume of dredging required), the operational conditions (i.e., the water depths at the location of dredging and the capability of the equipment to maneuver in the large tidal ranges and strong currents), the compatibility with dredge disposal (i.e., equipment, methods, and location), equipment productivity, potential environmental impacts (e.g., suspended sediment and sound), and practicability (cost, technology, and logistics). Dredging equipment and methods were considered individually and in combination.

Characteristics of the Dredged Material (In-situ Sediment)

The dredged material is expected to be largely hard-packed sandy silt, fine-grained sand, clay, and granular material, with some isolated boulders. Mechanical dredges are suited for a variety of sediment types but typically achieve low production rates in hard-packed sediment and may require loosening of the sediment (by scarifying the sea floor) before dredging. Several different types of mechanical dredgers (such as clamshell or buckets) would be capable of dredging at this site. When comparing hydraulic dredgers, cutterhead suction dredges are designed to cut through and liquefy hard-packed sediment and even soft rock; whereas, other types of suction dredges are primarily suitable for loose and fine-grained sediment. Because the sediment to be dredged at the site is hard packed, the cutterhead dredge would be the most appropriate type of hydraulic dredger to use for this site.

Operational Conditions

Both mechanical and hydraulic cutterhead dredgers would be capable of working with the large tidal ranges and strong currents located at this dredge site. Mechanical and hydraulic cutterhead dredgers would also be capable of conducting the dredging to required depths (average 10-foot cut) and over the required area (ranging from approximately 25–50 acres), although multiple dredgers may be mobilized to conduct the activities during a single open-water season in Cook Inlet.

Equipment Productivity

Hydraulic dredging is generally more productive than mechanical dredging, with mechanical dredging productivity estimated to be approximately 3,000 to 8,000 cubic yards per 24-hour shift and hydraulic cutterhead dredging productivity estimated to be approximately 20,000 to 30,000 cubic yards per 24-hour shift at the Project site.

Compatibility with Dredge Disposal Equipment and Methods

Both mechanical and hydraulic dredging methods are compatible with varying dredge disposal methods. Dredged material transport by split-hull barges and direct piping of fluidized dredged material are two primary dredge disposal methods. Decanting/dewatering of the dredge material in the barges at the dredge site would be conducted to maximize the amount of dredged material in each barge and therefore minimize the number of transits from the dredge location to the dredge placement location. Transport of dredged material as a slurry by submerged/floating pipeline if a hydraulic cutterhead dredger were to be used would pose some environmental advantages with respect to lower turbidity and decreased vessel traffic and vessel emissions, but its use may be precluded if use of a submerged/floating pipeline limited or inhibited vessel transit and navigation. Furthermore, operation of a submerged/floating pipeline may be complicated by the strong tides and currents in Cook Inlet as well as the distance between the dredged area and the dredge disposal area. A booster pump may be required if the distance between the dredge area and dredge disposal area exceeds approximately 1 mile.

Practicability

Practicability considerations for dredging equipment selection include currently available technology, logistics, and cost. Hydraulic cutterhead dredgers are less common than mechanical dredges. There are no hydraulic cutterhead dredgers located in Cook Inlet on a permanent basis. The hydraulic cutterhead dredgers therefore have higher mobilization costs than mechanical dredgers, which typically limits their economic viability to use for larger dredge projects. However, the magnitude of this dredging project may justify the mobilization and use of a hydraulic cutterhead dredge.

Environmental Impacts – Turbidity

As discussed in Resource Report No. 2, Cook Inlet has naturally high turbidity levels due to large inflows of sediment from glaciers and rivers. Turbidity generated by dredging is still a consideration for dredging equipment selection, just to a lesser degree than for areas with greater water clarity.

Hydraulic dredgers typically result in lower temporary water quality impacts at the dredge site than mechanical dredges (USACE, 1978). Most of the turbidity generated by a cutterhead dredging operation is usually found in the vicinity of the cutter. The levels of turbidity are directly related to the type and quantity of material cut, but not picked up, by the suction. The ability of the dredge's suction to pick up bottom material determines the amount of cut material that remains on the bottom or suspended in the water column. In addition to the dredging equipment used and its mode of operation, turbidity may be caused by sloughing of material from the sides of vertical cuts, inefficient operational techniques, and the prop wash from the tenders (tugboats) used to move pipeline, anchors, etc., in shallow waters. Based on limited field data collected under low current conditions, elevated levels of suspended material appear to be localized in the immediate vicinity of the cutter as the dredge swings back and forth across the dredging site. Within 10 feet of the cutter, suspended solid concentrations are highly variable but may be as high as a few tens of parts per thousand; these concentrations decrease exponentially from the cutter to the water surface. Near-bottom suspended solid concentrations may be elevated to levels of a few tenths of a part per thousand at distances of less than 1,000 feet from the cutter (USACE, 1983).

The turbidity generated by a typical clamshell dredger operation can be traced to sediment suspension occurring when the bucket impacts on and is pulled off the bottom, when turbid water spills out of the bucket or leaks through openings between the jaws, and when material is inadvertently spilled during the barge loading operation. Variability in the amount of material re-suspended by clamshell dredges is due to variations in bucket size, operating conditions, sediment types, and hydrodynamic conditions at the dredging site. A turbidity plume extends in the water column, with the plume generally larger at the bottom than at the surface. Maximum concentrations of suspended solids in the surface plume decrease rapidly with distance from the operation due to settling and dilution of the material. The near-bottom plume will have a higher solids concentration, indicating that resuspension of bottom material near the clamshell impact point is probably the primary source of turbidity in the lower water column. The visible near-surface plume dissipates rapidly (within an hour or two) after the operation ceases (USACE, 1983).

Bucket dredges remove the sediment being dredged at nearly its in-situ density and place it in barges or scows for transportation to the disposal area. Although several barges may be used so that the dredging is essentially continuous, disposal occurs as a series of discrete discharges. Dredged material removed by a clamshell remains in fairly large, consolidated clumps and reaches the seafloor in this form. The dredged material descends rapidly through the water column to the seafloor, and only a small amount of the material remains suspended (USACE, 1983).

The operation of a cutterhead dredge produces a slurry of sediment and water discharged at the disposal site in a continuous stream. As the dredge progresses across the dredge site, the pipeline is moved periodically to keep abreast of the dredge. The discharged dredged material slurry is generally dispersed in three modes. Any coarse material, such as granular material, clay balls, or coarse sand, will immediately settle to the bottom of the disposal area and usually accumulates directly beneath the discharge point. The vast majority of the fine-grained material in the slurry also descends rapidly to the bottom in a well-defined jet of high-density fluid, where it forms a low gradient circular or elliptical fluid mud mound.

Approximately 1 to 3 percent of the discharged material is stripped away from the outside of the slurry jet as it descends through the water column and becomes suspended as a turbidity plume (USACE, 1983).

Although the majority of heavy metals, nutrients, petroleum and chlorinated hydrocarbons are usually associated with the fine-grained and organic components of the sediment (USACE, 1978), there is no biologically significant release of these chemical constituents from typical dredged material to the water column during or after dredging or disposal operations. Levels of manganese, iron, ammonium nitrogen, orthophosphate, and reactive silica in the water column may be increased somewhat for a matter of minutes over background conditions during open-water disposal operations; however, there are no persistent defined plumes of dissolved metals or nutrients at levels significantly greater than background concentrations (USACE, 1983).

Environmental Impacts – Sound

Dredging operations can produce underwater sound that may be audible to marine mammals. Sounds associated with mechanical dredging are typically intermittent. Sounds from mechanical dredging might include the sound of the bucket or equipment contacting the substrate, and ship/machinery sounds. Dredging with mechanical dredgers generally results in the generation of relatively low frequency underwater sounds, and generally at lower sound energy levels than does dredging with hydraulic dredgers such as cutterhead suction and trailing suction hopper dredges (Thomsen et al., 2009; CEDA, 2011; Wladichuk et al., 2015). Dickerson et al. (2001) measured a mechanical clamshell dredge and found it to produce sound pressure levels of 113 dB at 150 meters (or approximately 136.5 dB 10 meters) when dredging coarse mix of sand and granular material, and 107 dB at 10 meters when dredging soft sediments. The greatest sound energy levels were produced by the bucket striking the seafloor.

Dredging with hydraulic dredgers results in continuous underwater sound being generated and generally produces underwater sound levels that are greater than those associated with mechanical dredging. Trailing suction hopper dredges generally produce greater sound energy levels than do cutter suction dredges (CEDA 2011; Wladichuk et al. 2015). Hydraulic dredgers have been reported to produce sound at levels ranging from 157.5 dB at 1 meter source (Reine and Dickerson, 2014) to 189 dB at 1 meter (Robinson et al., 2011, Reine et al., 2012). Robinson et al. (2011) measured six trailing suction hopper dredges and reported a maximum broadband source sound pressure level of 189.9 dB at 1 meter. Reine and Dickerson (2014) found noise levels from a hydraulic cutterhead dredge in California to attenuate to 120 dB in about 180 meters. Greene (1985, 1987) found source levels of 178 dB at 1 meter emitting from a hydraulic pipeline (cutterhead suction) dredge in the Arctic waters of Alaska.

While there are some differences in underwater sound produced by mechanical and hydraulic dredgers, the differences did not drive selection of the proposed dredging equipment and both types of equipment may cause temporary behavior reactions but not temporary or permanent injury or mortality. A further discussion of dredging-related sound levels and potential impacts to marine mammals is provided in Resource Report No. 3.

Conclusions

Based on this review of mechanical and hydraulic dredgers as potential alternatives for dredging equipment, the Applicant plans to retain both types of equipment as options for MOF dredging given that significant differences in potential environmental effects between these options have not been identified.

10.6.4.1.2 GTP West Dock

The Applicant's Proposed Alternative does not require dredging of a navigation channel or the alternate dock locations.

10.6.4.1.3 Marine Terminal

Options for dredge material disposal that were considered include beneficial use of the material, in-water and nearshore placement, and upland placement. Considerations for the selection of dredge material disposal options include the availability of the site, dredged material physical and chemical compatibility, potential environmental impact, and practicability (cost, technology, and logistics). Dredge material disposal options were considered individually and in combination.

10.6.4.1.3.1 Beneficial Use

The full range of beneficial use options was initially considered. Because there were not known local or regional opportunities for certain beneficial use options and because the dredged material would come from a marine rather than freshwater environment, the following options were eliminated from further analysis: habitat restoration, sustainable regional sediment management, aquaculture/agriculture/forestry/ horticulture, recreational development, commercial land development (reclamation), or commercial product development. The beneficial use options of beach nourishment, shoreline stabilization and erosion protection, and engineered capping were carried forward as options for consideration.

Beach Nourishment, Shoreline Stabilization, and Erosion Protection

In the immediate vicinity of the Project site, beach processes are causing moderate to significant erosion of the bluffs along Cook Inlet (Smith et al., 2003). In 2007, the Kenai Peninsula Borough and the Kachemak Bay Research Reserve collaborated on a Kenai Peninsula bluff erosion project extending from Homer to the Forelands. Using remote sensing techniques, this study found bluff retreat rates of up to 3 feet per year with some erosional hotspots up to 6 feet per year (Eggleston et al., 2010). In the Project vicinity, bluff retreat rates have been documented to be greater than 2 feet per year (Eggleston et al., 2010).

Bluff toe protection and beach fill (replenishment) are thought to be helpful in maintaining the stability of the beach (Smith et al., 2003); therefore, beneficial reuse of the dredge material to ameliorate coastal stability issues was considered to be an option that was carried forward for preliminary analysis. Despite that there is documented bluff erosion in the vicinity of the Project site, the public use of the beach and beach access for purposes of recreation and fishing (commercial and personal use) reduce the likelihood that the Project could find adequate sites requiring material to accommodate the full volume of dredge material requiring disposal. Therefore, beneficial use was considered as an option that may be pursued only for a portion of the total dredge volume and therefore in combination with other dredge disposal options.

The Applicant considered but do not currently plan to use dredged material for bluff protection or stabilization during construction or operations at the Project site. During Project construction, geotubes would be placed on the bluff to prevent erosion as a more stable form of erosion protection than dredge material, which would be considered a more sacrificial form of erosion protection. The Applicant also considered potential locations off site for beneficial use. The beach in the vicinity of the Project site is used during the summer months for public access and recreation as well as commercial fishing activities, and therefore the practicability and safety of handling and hauling large volumes of material (particularly on the changing beach surface in the tidal environment) while maintaining access for the public reduces viable opportunities to those in the immediate vicinity of the site. Several offsite locations on the Kenai Peninsula have preliminary plans for beach nourishment projects. However, the known sites are not currently permitted and are located between 40–60 miles south of the proposed Project site, a distance that would add considerable time and cost to the scope of the dredging operation. Therefore, these opportunities were not pursued further and beach nourishment is not currently a proposed dredge disposal option.

Engineered Capping

The dredged material may be suitable as landfill soil cap, however likely in smaller volumes than the total dredged material volume anticipated for this Project. Discussions about the need for this material at the local landfill for purposes of engineered capping have not occurred. Important considerations for this option are the salinity of the dredged material, the distance to the nearest landfill with capacity or need for landfill cover, the total volume of capacity for the landfill, the potential need to store or stage dredge material until it is required for use at the landfill, and the practicability of handling and hauling large volumes of dredge material.

Fill for Project Development

The dredging is planned to occur adjacent to the LNG Plant, which would require earthworks and site preparation to grade and engineer fill and foundations for the planned facilities. The Applicant investigated whether the dredged material could be used as structural fill for site civil works, or used for construction of the MOF or access road from the MOF to the top of the bluff. Considerations for this option included suitability of the dredged material as fill, the timing of the dredging and construction activities, and any additional operational requirements for using dredged material as fill.

Geotechnical studies at the site have shown that the properties of the dredge material vary vertically and horizontally across the dredge area. Whereas some of the material is granular material (sand, silty sand, and a very small amount of granular material/cobbles) it is not consistent enough to be suitable for upland construction fill for site works or haul roads without segregation.

Use of the dredged material would therefore require building an upland dewatering area, segregating the better-quality material and potentially chemical treatment (lime and/or cement) of the fine-grained material to make it suitable for fill. This would result in increased land use for dewatering, segregating, and stockpiling, increased vehicle emissions and traffic for movement of dredged material, and increased cost. The dredged material that is not used as fill would need to be placed in a suitable location off site. Furthermore, it is anticipated that onshore onsite civil works would result in a balancing of cut and fill such that the required fill would be available from excavation on site without use of offsite granular material or other material sources, and also without the need for dredged marine sediments. Therefore, use of dredged material as structural fill on site does not offer any additional benefits (environmental or otherwise) over other sources of fill or other options for dredged disposal.

10.6.4.1.3.2 Upland Placement (Non-Beneficial Use)

Upland placement is the placement of dredge material on land above the mean high water line. The current estimated dredged material volume of up to 1 million cubic yards would require over 1,000 acres if placed at a depth of 1 foot, or over 100 acres if placed at a depth of 10 feet deep. After excavation, dredged material would be dewatered and transported on shore to the location of disposal, requiring access to nearby docks and roads, many of which would likely already be experiencing increased usage due to Project construction.

The upland placement site would be prepared with berms to contain the wet dredged material and retain any free water to prevent erosion and manage the return of that water back to Cook Inlet. Weirs and pipes would be used to control the retention and discharge of any free water to allow sufficient settling time to retain the dredged solids and minimize suspended solids on the water to reduce turbidity at the outlet of the return water pipes in Cook Inlet. Hydraulically dredged sediment could potentially be pumped directly to the placement site, but the resulting slurry (which typically consist largely of water at about 20–30 percent solids concentrations) would require a larger containment area and larger capacity weirs(s) and return pipes to allow for enough retention time, and ponding depth for the free water to maintain low turbidity water quality in the return water. Mechanically dredged material would be partially dewatered from the barges at the dredge site before being transported to an unloading facility. Although the material would have a very high water content, relatively little free water is expected and so the retention facility would be smaller than required for hydraulically dredged/placed material. The retaining berms, weirs, and return pipes may be smaller, but the overall configuration would be very similar to a hydraulic dredge material retention facility. This concept would keep saline and turbid decant water from entering nearby freshwater bodies (streams and lakes). The settling behavior of dredged sediment minimizes intrusion of decant water into the underlying groundwater with essentially all of the free water coming to the surface where it could be discharged over a weir into a piping system to return to Cook Inlet.

No potential upland sites in the Project vicinity have been identified that would accommodate or be available for the dredged material. There is no space available on site for upland placement of dredge material since Project land is allocated for Project facilities, infrastructure, and construction use. Therefore, dredge material upland placement would need to be off site. The presence of freshwater waterbodies and groundwater sources in the vicinity of the Project and the dredged material's origins in the marine environment thereby requiring a means to treat (i.e., dewater) the dredged material before placement makes this option for dredged material placement not practicable. Offsite upland placement options would increase the potential environmental impacts such as vehicle emissions and would have significant Project costs associated with the re-handling of the dredged material and the transport and placement of material at the end location. There are not clear benefits to upland placement of dredged material for this Project.

10.6.4.1.3.3 In-Water and/or Nearshore Placement (Non-Beneficial Use)

In-water disposal would consist of dredged material being placed below the water surface at a specific location. Factors that were considered for in-water and nearshore placement include minimizing turbidity for sensitive receptors, reducing total vessel transit, ensuring navigability (i.e., depth/clearance) for other vessels, minimizing interruption to normal vessel traffic transiting Cook Inlet, and avoiding accumulation of material downstream.

The only known existing in-water disposal site in the Project vicinity is used by the USACE, which is responsible for maintenance dredging to enable navigability of ships to the Port of Anchorage. The site is located at Fire Island, approximately 60 miles up Cook Inlet from the Marine Terminal and is located in relatively deep water (-38 feet to -90 feet MLLW) (USACE, 2013). At this location, the tides and currents can exceed 5 knots and discharged material is rapidly suspended and dispersed into the already highly turbid waters of Upper Cook Inlet (USACE, 2013). The site is not currently permitted to accept materials other than material that is dredged by USACE. Disposal of dredged material from this Project to the USACE disposal site would add significant cost and time to the dredging operation. It could take more than 24 hours for a loaded barge to be transported up Cook Inlet by tug and then return to the dredge site. Multiple tugboats and barges would be required to support a single dredge and minimize downtime at the dredge. This would reduce dredging production rates and increase costs to the point of not being viable for the Project. The number of tugboats operating in Cook Inlet to support this operation would also increase air quality impacts from the tugboat engine emissions.

Permitting of a new aquatic disposal site in closer proximity to the Project site is also under evaluation. A potential dredge disposal area located within 5 miles to the west of the dredging area has been identified. The location is in relatively deep water (-60 feet to -100 feet MLLW) with strong currents (over 6.5 knots peak flood and over 5.5 knots peak ebb based on preliminary modeling). This deep water and residual current flow could disperse the dredged material placed at the site, while minimizing impacts to navigation. The location to the east of the main navigation channel used by the majority of vessel traffic transiting north of Nikiski and to the west of the vessel traffic transiting to/from the Nikiski terminal minimizes potential impact to other waterway users. This is confirmed by historical vessel Automatic Identification System traffic data. The high currents and deep water depth are expected to rapidly disperse sediments and decrease potential for depressed levels of dissolved oxygen due to high oxygen demand associated with dredge material.

Federal jurisdiction of Cook Inlet waters under the Marine Protection, Research, and Sanctuaries Act begins in Lower Cook Inlet south of the southernmost point of Kalgin Island, which is approximately 30 miles to the southwest of the Project's dredging area. This distance is too far for transport of dredged material because it would lengthen the construction schedule and result in increased vessel traffic and emissions. Therefore, all practicable dredge disposal sites for the Project are located within state waters of Cook Inlet. Any aquatic disposal sites located at greater distances south or west of the Project site would result in increased equipment requirements and vessel trips for transport of dredged material.

10.6.5 Associated Facility Alternatives

Associated facilities (e.g., pipe storage areas and contractor yards) have been sited in proximity to active construction areas taking into consideration any safety concerns (e.g., buffer areas). The Project has prioritized siting of the associated facilities either in existing disturbed areas or within the construction ROW (e.g., helipads) to the extent practicable.

The pioneer (or mobile) camps required for the early, enabling civil works are proposed to be located in existing gravel pits, at existing camp sites, or on the site pads being constructed as part of the enabling civil works (i.e. the construction camp pads, compressor stations, pipe storage yards). The facilities construction camps and contractor yards are also collocated at the facilities site locations.

Pipeline construction camps were sited based on the following general criteria, as practicable:

- Using existing camp sites;
- Limiting the travel distance from a camp to a maximum of 30 miles;
- Selecting sites close to existing infrastructure or disturbances; and
- Selecting sites convenient for co-location with other Project infrastructure.

Based on the above criteria, the proposed Mainline construction camp locations include:

- Existing camp sites (e.g., Franklin Bluffs, Happy Valley, Galbraith Lake, Dietrich, Coldfoot, Old Man and Livengood);
- Locations close to existing infrastructure or disturbances (e.g., Beluga Marine Camp, Prospect, Healy and Cantwell (in existing or old gravel pits);
- Locations co-located with other Project infrastructure (e.g., Dunbar and Hurricane (near rail sidings to be used by the Project);
- Locations close to existing public access (e.g., Prudhoe Bay, Five Mile, Rex, Chulitna, Sleeping Lady and Kenai); and a location that is isolated but on a flat upland area adjacent to the pipeline ROW (e.g., Susitna).

Construction camp locations were reviewed by a multidisciplinary team to ensure construction (e.g., abutting existing infrastructure, ice pad placement) and environmental (e.g., wetlands and waterbodies, cultural resources, noise sensitive areas) considerations were weighed during final camp siting at each location. Adjustments made to minimize impacts included:

- Prudhoe Bay Camp (MP 0.61) – The camp was shifted to abut the planned GTP access road and to where the pipe yard is located. The camp will be built over several ponds using an ice pad to minimize impacts;
- Five Mile Camp (MP 353.68) – The camp was shifted southeast to avoid wetland areas;

- Dunbar Camp (MP 456.06) – The site boundary was revised to avoid the Minto Flats State Game Reserve; and
- Sleeping Lady Camp (MP 744.88) – The camp and associated pipe yard were shifted north to avoid wetland areas.

10.6.6 Material Sites

The Project is evaluating alternative material sites for sources of granular material during construction. A preliminary list of potential sites is provided in Resource Report No. 6, Appendix F, the Project's *Gravel Sourcing Plan and Site Reclamation Measures*. Working with the mine site owners and landowners, agencies, and construction planning staff, the Applicant has identified the potential sites suitable for use by the Project.

10.6.7 Water Sources

The Project is evaluating sources of water for hydrostatic testing, ice roads, ice pads, ice road and ice pad construction, dust control, camp use, concrete mixing, and trenchless method mud make-up, among other uses. A potential listing of the sources of water is provided in Resource Report No. 2, Appendix K. Working with ADF&G, existing water rights parties, DMLW, and ADEC., the Project have identified the potential list of water sources.

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